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Feasibility Study:
Hydroelectric Power
in the
Santa Clara Valley

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SANTA CLARA VALLEY WATER DISTRICT

FEASIBILITY STUDY: HYDROELECTRIC POWER IN THE SANTA CLARA VALLEY

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November 1981

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INTRODUCTION

A primary responsibility of the Santa Clara Valley Water District is to ensure an adequate quantity of water for the community. To meet this responsibility, the District operates its dams, reservoirs and recharge facilities for maximum conservation of water. However, these facilities are available for other uses as long as they are compatible with the District's conservation goals. One of these compatible uses is the generation of electricity by the use of hydrodynamic power at the base of these dams. The primary purpose of this report is to examine hydroelectric power generation at the District's major conservation reservoirs within the County and to determine their economic feasibility. This report prioritizes those sites for which development appears economically justified and encourages further action.

Previous Studies

This report serves to update the November 1978 study prepared by Tudor Engineering Company of San Francisco titled "Hydroelectric Power Potential in the Santa Clara Valley". The Tudor report examined hydroelectric generation at the District's reservoirs, as well as along the Santa Clara Conduit. The results of the Tudor studies were based on September 1978 discounted energy rates of $0.01656/KWH and some very preliminary reservoir operation studies furnished by the District. These operation studies examined only a very limited hydrologic period and did not consider a number of reservoir operating constraints such as those imposed on Coyote Reservoir by the Department of Water Resources' (DWR) Division of Safety of Dams.

Small Scale Hydropower

Recently, hydroelectric power has become economically feasible on a scale not previously justified. The rapid regrowth of "small-scale hydropower" (electrical generating capacity less than 15 MW) in the past few years is due to a number of factors. The single most important factor is the continuing increase in the cost of fossil fuels. Currently, forty percent of California's electrical energy is generated using fuel oil. Because of this great dependency on fuel oil, energy costs have risen proportionally to fossil fuel costs. Additional factors contributing to more widespread feasibility of small-scale hydroelectric power projects include:

1. Continued escalation of energy prices above the general inflation rate.
2. New Federal and State regulations including the Public Utility Regulatory Policy Act (PURPA) and the California Public Utility Commission (CPUC) energy regulations intended to encourage development of alternative energy resources.
3. Interest expressed by utilities in purchasing power from qualified generation facilities using cogeneration, fuels derived from biomass, woodwastes or refuse and certain renewable resources, such as water.
4. Rebirth in the manufacture of small turbines/generators.

All of these factors taken together have increased the attractiveness of small-scale hydroelectric power as a safe, clean way to provide more energy at lower cost to the people of California.

Santa Clara Valley Reservoirs

The Santa Clara Valley Water District (SCVWD) owns and operates seven major dams and reservoirs in Santa Clara County. These reservoirs were all examined to assess the economic feasibility of installing hydroelectric generating facilities. The map in Figure 1 shows the locations of the reservoirs.

SANTA CLARA VALLEY WATER DISTRICT RESERVOIRS

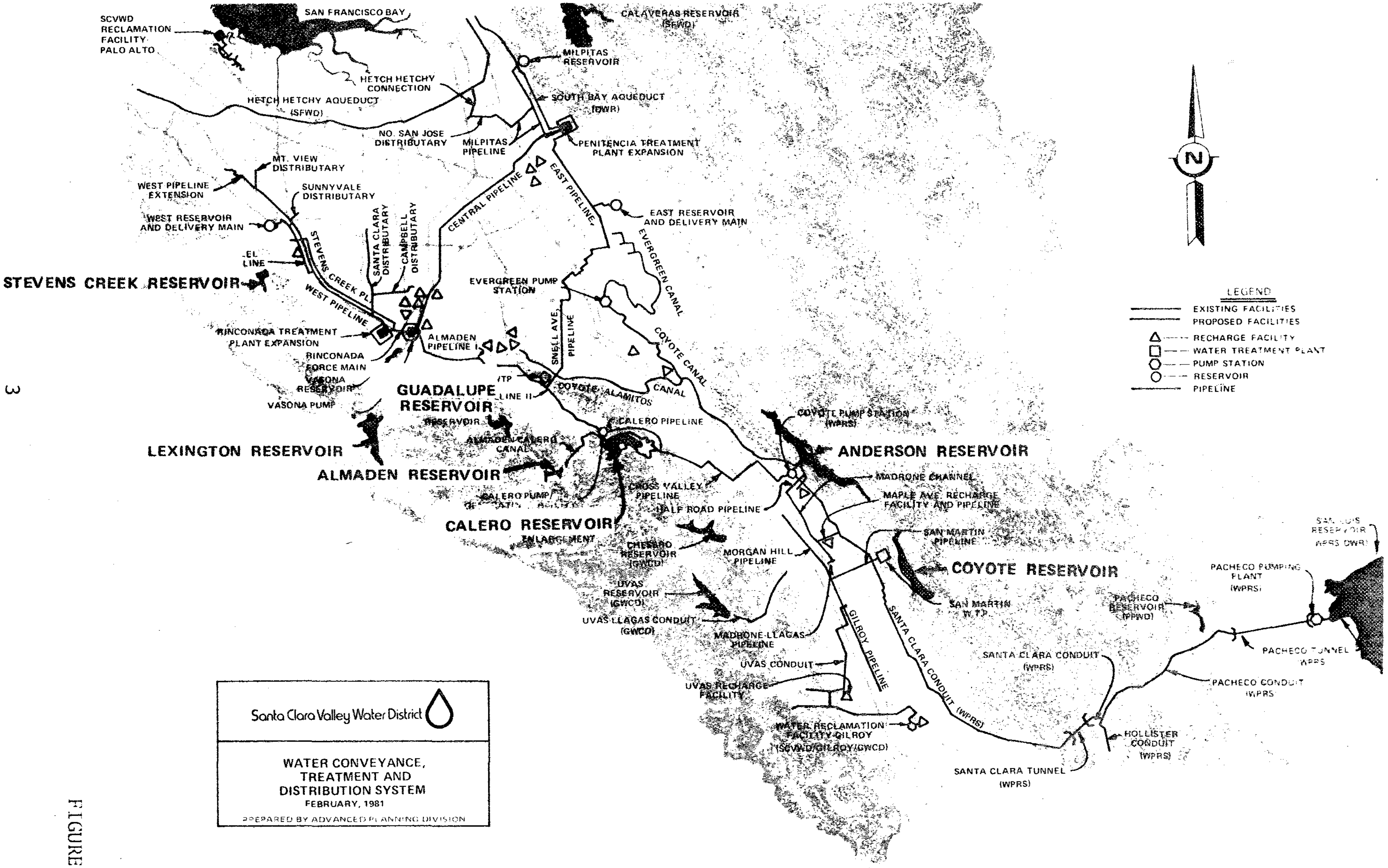


FIGURE 1

These reservoirs are used primarily to impound water for groundwater recharge with secondary benefits of recreation and incidental flood control. In a few cases, water is also taken directly from the reservoir by open channel for irrigation purposes. When water is released from the dams through the outlet works, energy is dissipated through valve structures. The projects proposed in this report would capitalize on this wasted energy and convert it to useful electrical energy. At most of the reservoir sites, the necessary power plant equipment could be connected directly to the existing outlet works.

Conveyance and Distribution System

While the primary purpose of this report is to examine hydroelectric power generation at the District's major reservoirs, the potential for hydroelectric generation may also exist along the District's conveyance and distribution system as well as along the Bureau's Santa Clara Conduit. As with reservoirs, energy is often dissipated as releases are made from pressure pipelines into recharge facilities or into other pipelines. Numerous sites along conduits, such as at the proposed Maple Avenue Turnout (Santa Clara Conduit), the Kirk and Page Turnout (Central Pipeline), the proposed Alamitos Creek Turnout (Almaden Pipeline), and various treated water turnouts such as at the City of Santa Clara Turnout are also being examined and will be the subject of a subsequent report.

In addition, this subsequent report will also examine hydroelectric generation at Vasona Reservoir.

Summary of Results

The results of the economic analysis of hydroelectric generation at the District's reservoirs indicate that at least four sites are economically feasible at the present time. They are Anderson, Calero, Lexington and Coyote. Immediate action is recommended to secure the required licensing at these four sites and to initiate final feasibility studies.

The significant data for all seven sites investigated is presented in Table 1, including proposed capacities, estimated average annual energy, and capacity factors. The capacity factor of a plant is the ratio, expressed as a percent, of the estimated average yearly energy generation to the amount of energy that would be produced if it were operated at full capacity for one year. The capacity factor is a common factor used for evaluating the relationship between the cost and the value of generation.

TABLE 1

SUMMARY OF SIGNIFICANT DATA

HYDROELECTRIC POTENTIAL
SANTA CLARA VALLEY WATER DISTRICT

Site	Proposed Power Plant Capacity (KW)	Average Annual Energy (MWH)	Capacity Factor (%)	Capital Cost ($)	Benefit-Cost Ratio [1]	Residential Equivalents [2]
ALMADEN	95	230	28	1,048,000	.30	80
ANDERSON	960	4,620	55	1,568,000	4.02	1,605
CALERO [3]	1,440	4,430	35	2,032,000	2.98	1,540
COYOTE	322	1,000	36	1,292,000	1.06	345
GUADALUPE	127	350	32	1,071,000	.45	120
LEXINGTON	840	2,460	33	1,952,000	1.72	855
STEVENS CREEK	127	422	38	1,210,000	.48	145

---

[1] Based on a discounted energy rate of $.05683/KWH, escalated at 2% per year above the general rate of inflation.

[2] Number of homes for which this site could supply annual residential electrical needs, based on Pacific Gas and Electric's residential lifeline rate of 240 KWH per household per month.

[3] Includes power generated from the modulation of flow in pipelines.

HYDROELECTRIC POWER IN THE SANTA CLARA VALLEY

For decades the United States has had an abundance of cheap energy. However, since 1973, the cost of energy has drastically increased and has received enough notoriety to establish an intrinsic value. This has resulted in drastic changes in our lifestyle. This section discusses changes that have occurred in the economic evaluation of hydropower production and also describes potential markets for this power.

Value of Power

The value of power is usually determined in two parts. The first part is attributed to the dependable capacity of the plant, that is, the portion of the plant capacity that is available on a continual reliable basis to meet the peak of the energy demand curve. The second part is attributed to the energy output from the plant. Due to their limited storage capacity and mode of operation, none of the District's reservoirs are considered to have any dependable electrical capacity. Therefore, the potential value of District power would be based solely on the total amount of energy generated and would not be valued for a dependable electrical producing capacity.

Since the Public Utility Regulatory Policies Act (PURPA) was passed in 1978, the value of energy generated by small power production facilities and cogeneration facilities has been determined in such a manner as to encourage development of these alternative sources of energy. Under PURPA, electric utilities must presently purchase generation from small hydro projects at a price equal to the costs that the utilities would incur producing this additional energy themselves, or purchasing this energy from other sources. In other words, the energy is presently valued at the "avoided cost" to the utilities.

In California, the California Public Utilities Commission (CPUC) has moved quickly to implement the policies established by PURPA. Under order from CPUC, most of the California electric utilities such as Pacific Gas and Electric Company (PG&E) and

Southern California Edison have published cogeneration rates based on their avoided cost and have been authorized to purchase power from cogeneration facilities at such rates.

In California, the electrical energy produced at small scale hydroelectric plants would generally replace energy production from gas and/or oil-fired generating facilities. Despite the fact that California is the fourth largest producer of oil and gas in the U.S., two-thirds of its energy supplies are being imported. The avoided cost of energy is thus directly tied to the current and future cost of fossil fuel, primarily oil. It is estimated by the California Energy Commission (CEC) and other knowledgeable sources that future prices of energy will continue to escalate at anywhere from two to ten percent above the general rate of inflation. This trend will most likely cause the cost-effectiveness of small-scale hydro plants to increase significantly with time.

While PURPA presently requires the electrical utilities to purchase energy at their "avoided cost", the avoided cost can vary among utilities both in terms of present and projected future rates. The variation in rates generally reflect their level of dependency on gas and/or oil, as opposed to other sources of power. Since the individual utilities adjust their PURPA rates quarterly, the rates reflect other alternative sources of energy that may be available to the utility, such as other hydroelectric generation, geothermal energy etc.

Potential Power Purchasers

There are a number of options under which the District could market its power. The first would be to sell it to PG&E, at the rates specified by PG&E under the CPUC's implementation of PURPA, or at some other rate determined by agreement with PG&E. PG&E is the major electrical utility in the Santa Clara Valley and throughout much of Northern California. PG&E sells power to industries, municipalities and individuals over the entire area. In addition to PG&E, other major electrical utilities such as Southern California Edison and San Diego Gas and Electric, may be interested in purchasing the District's power and wheeling it into their system.

Other potential purchasers of the District's power are public agencies such as the City of Santa Clara. Santa Clara, along with other cities, purchases power wholesale from PG&E and the Western Area Power Administration (WAPA) to distribute over municipally-owned distribution systems to their retail users. Power such as that produced by the District would provide alternative or additional sources for future growth.

Other potential purchasers are the California Department of Water Resources (DWR) and the Western Area Power Administration (WAPA). These agencies purchase power to operate the pumping plants of the State Water Project and the Central Valley Project, respectively. In addition, WAPA desires to purchase additional energy to help improve its energy situation. Both of these agencies may wish to negotiate for the purchase of District power.

Major industries have also expressed interest in purchasing the entire output of small power plants as an alternative to buying commercial power. Another option available to the District is to utilize directly the power generated to meet all or a portion of its own energy requirements.

ANALYSIS OF POTENTIAL POWER GENERATION

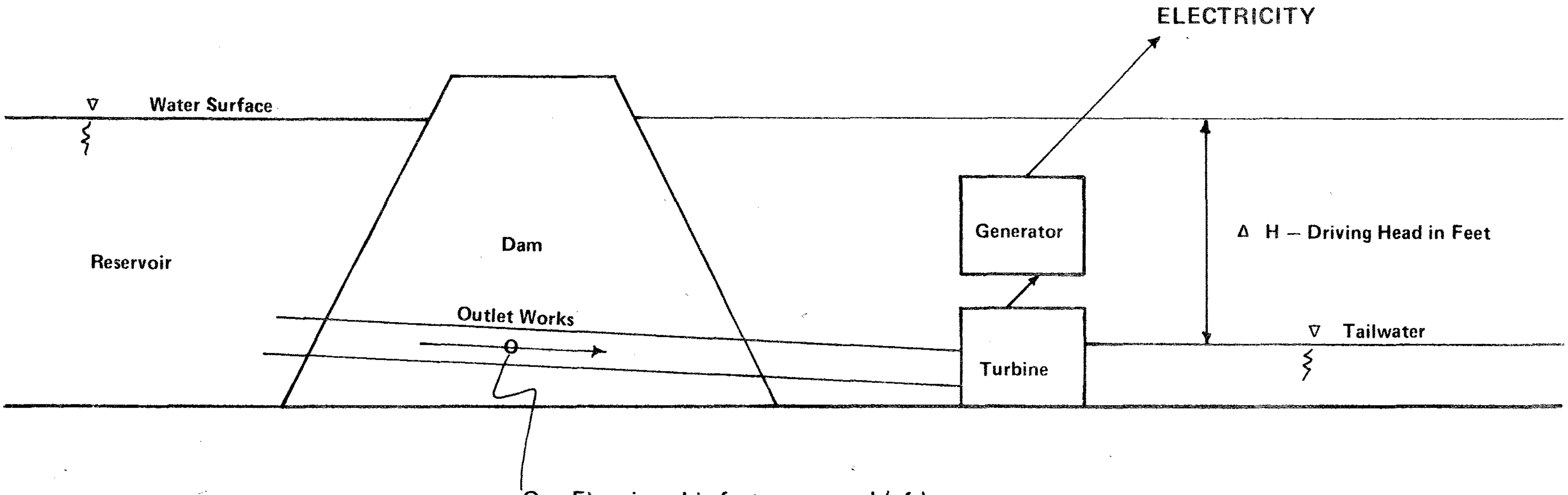
Hydroelectric power is developed by converting the potential energy of water in a reservoir to useful electrical energy. Water released from a reservoir flows through the outlet works of the dam and is used to drive a turbine. The turbine in turn drives a generator which converts kinetic energy into electrical energy. The force which drives the water is the head on the turbine, which is equal to the difference between the water surface elevation of the reservoir and the tailwater downstream of the dam. This is illustrated in Figure 2.

Method of Analysis

The analysis of the potential hydroelectric power generation at the District's reservoirs utilized the computerized system simulation model "SYSMOD". With the use of the SYSMOD model the impacts of including hydroelectric generation as part of the operation of the reservoirs were evaluated. The reservoirs were operated for maximum water conservation within the District's operating policies as well as any imposed by DWR's Division of Safety of Dams and/or the State Department of Fish and Game.

The potential energy generation was based on average monthly releases and average monthly water surface elevations. In conjunction with turbine operating characteristics, the above were used to calculate the monthly energy which could have been generated at a reservoir site had a specific size turbine been in operation. From a month by month analysis of each of the historical years, the amount of yearly generation was computed. The long term average yearly energy generation was then determined and used to evaluate the energy benefits at a site.

CONFIGURATION OF HYDROPOWER ADDITION AT A TYPICAL RESERVOIR SITE



Q – Flow in cubic feet per second (cfs)
1 cfs = 449 gallons per minute

$$\text{POWER (Kilowatts)} = \frac{Q * \Delta H * e}{11.82}$$

e – efficiency of turbine and generator
11.82 – conversion factor

FIGURE 2

General Description of Sites

The reservoirs examined in this study range in size of maximum storage capacity from 1,800 acre-feet to 91,000 acre-feet. All of the dams are either rolled earth or rolled earth and rockfill. The dams and reservoirs are owned and operated by the Santa Clara Valley Water District. Based on a preliminary examination, it appears that suitable area exists for powerhouse facilities at the base of all dams in question. With the exception of Lexington Dam, the reservoirs' outlet works are presently suitable for hydroelectric generation, and penstocks could be directly attached to these outlet works. Data on the various reservoirs and dams can be found in the Appendices. Those sites with specific peculiarities are discussed below.

Site-Specific Characteristics

Calero Reservoir

Upon completion of the Bureau's San Felipe project, the northern portion of Santa Clara County will receive imported water from the San Felipe Division of the Central Valley Project through the Cross Valley Pipeline and the proposed Calero Pipeline. In the analysis of potential generation at Calero, energy was generated from the modulation of flows from the Calero Pipeline into the Almaden Valley Pipeline, from releases to Calero Creek from Calero Reservoir and/or the Calero Pipeline, and from releases into Calero Reservoir from the Calero Pipeline, with the majority of the energy being generated from the modulation of flows from the Calero Pipeline into the Almaden Valley Pipeline.

Lexington Reservoir

At the present time, the outlet works of Lexington Reservoir are controlled upstream of the dam. This is the result of the unavailability of sufficient pressure pipe during the construction of the dam to complete the outlet pipeline. Hence, a 250-foot section of non-pressure pipe was installed at the downstream end of the dam which possibly would not withstand the back pressure that could be created during a sudden valve closure (the water hammer effect) at the power plant. In order to make the existing outlet works functional for pressurized flow to the penstock and powerhouse, the 250-foot section of non-pressure pipe would have to be replaced with pressure pipe by breaching a section of the embankment at the toe of the dam. A special cost has been estimated and included on the Lexington cost analysis for this modification.

The possibility of installing the 900 KW Hitachi-built Francis turbine, which the District already owns, was examined at the Lexington site. This site seems best suited for use of the 900 KW turbine. A cost analysis of this additional alternative is included in Appendix H.

Anderson Reservoir

Releases from Anderson and Coyote Reservoirs have historically, and are presently, being made for groundwater recharge of the Coyote Subbasin and portions of the Santa Clara Valley Subbasin. Minor releases also recharge a portion of the Llagas Subbasin. While studies on the coordinated operation of Anderson Reservoir and the Santa Clara Conduit have indicated a reduction in pumping requirements at the Bureau of Reclamation's Coyote Pumping Plant, the hydroelectric generation potential of Anderson Reservoir, operated in an uncoordinated mode, outweigh the savings in reduced pumping. In addition, the presence of a high level of asbestos in the Anderson Reservoir water could preclude its use in a coordinated operation. Hence, in the analysis of hydroelectric generation at Anderson, the reservoir was operated in a non-coordinated mode for maximum groundwater recharge.

Stevens Creek Reservoir

The Stevens Creek Dam is currently undergoing evaluations in light of recent findings that it does not meet earthquake safety standards at reservoir design capacity. Pending completion of the study and possible alterations to the dam and spillway, the reservoir at the present time is being run significantly below capacity. However, this is considered only an interim measure. In the analysis for hydroelectric generation, it was assumed that the reservoir will be operated using its full design capacity.

Reservoir Operation

Historically, the District's reservoirs have been operated for maximum conservation of local runoff. Releases from reservoirs are made for groundwater recharge and some minor stream diversions. None of the reservoirs are currently being used to meet treatment plant demands. It is not expected that their operational mode will significantly change in the future. Reservoir elevations were allowed to fluctuate between their maximum storage levels and their minimum recreational and fish pool elevations to maximize water conservation.

Turbine Size Optimization

Careful selection of a turbine with an optimal rated capacity for a specific site is necessary in order to maximize the amount of power which is produced at that site. There are both flow and head limitations on the operation of hydraulic turbines. As operating conditions diverge from the rated design conditions, such as conditions of excessively high or low flows, or excessively high or low heads, the efficiency of the plant drops off drastically. The plant should not be operated when flow or head conditions fall outside of the acceptable range for the specific type of turbine to prevent damage to the turbine. Furthermore, the generator may be damaged if the turbine output exceeds the capacity of the generator.

Turbine operational constraints were incorporated into the SYSMOD computer model. For the horizontal Francis units which were selected for all of the sites in this study, the acceptable range of turbine flows was limited to a maximum of 105 percent of the design flow and a minimum of 40 percent. Head values were limited to a maximum of 150 percent of the design head and a minimum of 50 percent.

By comparing the energy output from turbines of various rated turbine capacities, it was possible to select a turbine which maximized the generation at each site. This turbine size was then used in the economic analysis of the site. Table 2 shows the rated capacities selected and the average yearly energy generation for each of the sites.

TABLE 2

POWER AND ENERGY OUTPUT SUMMARY

Item	Symbol	Unit	SITES						
			Ander-son	Lexing-ton	Cal-ero	Coyote	Stevens Creek	Guadalupe	Almaden
Number of Units			1	1	2	1	1	1	1
Turbine Discharge									
Design	Q_d	cfs	80	85	185[4]	65	20	15	15
Maximum 105% Q_d	Q_{max}	cfs	84	89	194	68	21	16	16
Minimum 40% Q_d	Q_{min}	cfs	32	34	34	26	8	6	6
Gross Head									
Design	H_g	ft	175	145	115	75	95	125	95
Turbine Backpressure[1]	H_1	ft	5	5	5	5	5	5	5
Effective Head									
Design Head	H_d	ft	170	140	110	70	90	120	90
Maximum Head (150% H_d or Max Res El-TW)	H_{max}	ft	225	210	165	105	135	140	135
Minimum Head (50% H_d or Min Res El-TW)	H_{min}	ft	125	70	55	35	45	6	45
Plant Design Capacity (Q_dxH_dx.84[2])/11.82[3]	P	KW	960	840	1,440	322	127	127	95
Average Annual Energy	E	MWH	4,620	2,460	4,430	1,000	422	350	230

[1] 5 ft. backpressure assumed for preliminary analysis

[2] Combined turbine and generator efficiency

[3] Conversion factor

[4] Units at 85 cfs and 100 cfs

ECONOMIC ANALYSIS

This section outlines the criteria used to determine direct and indirect costs, and the energy benefits related to the development of hydroelectric power. Project capital costs were estimated using cost data furnished by the Electric Power Research Institute (EPRI) in their publication, "Simplified Methodology for Economic Screening of Potential Low-Head Small-Capacity Hydroelectric Sites," dated January 1981. Technology is still in the early stages of development for small-scale hydropower, hence detailed information on manufacturing costs for small turbine/generator units, construction and operating costs, and on operating conditions is not yet readily available. The cost data presented in the EPRI publication were generally for units larger than those proposed for District facilities. However, these costs were considered adequate for preliminary cost estimates.

The economic analyses in this report are based on the benefit/cost ratio method. The benefit/cost ratio is the sum of the present worth benefits divided by the sum of the present worth costs. A resulting benefit/cost ratio greater than or equal to one indicates that the project appears currently feasible and permit application is strongly recommended. Compilation of cost and benefit estimates for each of the sites can be found in the Appendices.

General Rate of Inflation

Benefit/cost ratios generally increase as the escalation rates used in the analysis increase, therefore, smaller escalation rates give more conservative benefit/cost ratios. Hence, the projected general rate of inflation becomes an important factor in the analysis.

While two digit rates of inflation have been occurring in recent years, the long-term average rate of inflation over the past 20 years has only been 4.06 percent. While future rates of inflation are not expected to return to historical lows, they have generally been projected to decrease in the future. Projected inflation rates as seen by the California Energy Commission were used in the analysis of hydroelectric power at the District's reservoirs. These projected rates, presented in Appendix I, varied from about nine percent in 1981 declining to about seven percent by the early 1990's.

Direct Costs

The following is a brief description of the units of a typical hydroelectric facility and the assumptions made in estimating direct costs of plant development. All of the direct costs were estimated based on July 1981 dollars.

Penstock

This is the conduit which would connect the existing outlet works to the upstream face of the powerhouse, transporting the flow to the turbines. A length of penstock of fifty feet was assumed in all cases. Penstock velocities were limited to a maximum of 18 feet per second for the larger plants and 12 feet per second for the smaller plants.

Bypass Structure

A bifurcation was placed upstream of the turbine to allow flow to bypass the turbine in the event that the powerplant is shut down for any reason. In the case of a two-unit plant, either two bifurcations or a trifurcation was placed to divide flow to the turbines or to bypass them completely. The bypass structure also comprised piping, a fixed cone dispersion valve and operator to discharge the bypass flow into the stream. The capacity of the bypass structure for cost purposes was estimated at the capacity of the outlet works.

Valves

In addition to the reservoir's existing outlet valve, which would remain on the upstream side of the bifurcation, a butterfly valve would be placed just upstream of each turbine. For cost estimates, the capacity of butterfly valves was equal to the maximum turbine flow.

Powerhouse

A lump sum cost was estimated for the powerhouse, which would enclose the turbine and generator, and associated equipment. This lump sum cost covers the turbine and generator units, site civil works, powerhouse civil works, miscellaneous power plant equipment, accessory electric equipment, and turbine shut-off valve. Horizontal Francis turbines were selected as the best configuration at all sites.

Tailrace

The cost to excavate the channel transition (tailrace) immediately downstream of the turbine is included in the lump sum powerhouse cost. The cost of excavating an additional 50 feet of tailrace at the end of the transition was also included.

Switch Yard

These costs are the sum of civil costs and equipment costs corresponding to the transmission voltage required. The electrical system was assumed to be a generator breaker system with a required transmission voltage of 13.8 KV.

Transmission Line

As a conservative estimate, the cost of one mile of transmission line was included at each site, with a required transmission voltage of 13.8 KV. All of the sites are within close proximity of existing transmission lines. The cost includes tapping into an existing transmission line or substation, construction of the line and normal access, as well as wooden poles and associated electrical hardware.

Indirect Costs

Contingency

A contingency allowance of 20 percent of the direct costs was used. This allowance is to cover items which are unforeseen or have been inadvertently omitted.

Engineering, Administration and Construction Management

The costs for engineering, administration and construction management include expenditures for an environmental impact report, license and permit applications, preliminary and final design, construction management and administration. These costs were calculated as 20 percent of direct costs plus the contingency allowance.

Operation and Maintenance

Recurring annual costs for operation, maintenance, replacements, insurance and general miscellaneous expenses were estimated as 1.2 percent of the total project construction cost.

Cost of Capital

The cost of capital was charged at a twelve percent interest rate over a 20 year period. This is currently the maximum rate at which the District may legally obtain capital from the sale of revenue bonds.

Benefits

Value of Energy

By announcement, the following represent the PURPA rates as determined by PG&E under which they would purchase energy from qualified generation facilities using cogeneration, fuels derived from biomass, woodwastes or refuse, and certain renewable resources.

Time of Delivery Basis	For Meter Readings During October 1981
On-Peak, per KWH	$0.07752
Partial Peak, per KWH	0.07326
Off-Peak, per KWH	0.06542
Average Price, per KWH	$0.07104

PG&E's PURPA rates, both historical and projected have been generally lower than Southern California Edison (S.C.E.) and San Diego Gas and Electric Company (S.D.G.& E.). This reflects PG&E's lesser dependency on gas and oil and their greater use of hydroelectric and geothermal, and in the future, nuclear energy. The above energy prices are subject to change every three months to reflect PG&E's average quarterly costs of incremental fuel.

The above energy rates may also be subject to adjustment to account for such factors as the variance in energy dependence on hydrologic conditions and for transmission losses for energy to a "load center". In its August 1980 announcement on hydroelectric generation from facilities greater than 100 KW in size, PG&E indicated that the purchase price of energy from hydroelectric facilities such as the District reservoirs would be based on their published PURPA rates modified by three factors, F1, F2 and F3. The first factor, F1, is to account for the variance in energy production of a project due to its hydrologic conditions and also account for PG&E's oil inventory cost. The second and third factors, F2 and F3, are to adjust for transmission system losses. Being in PG&E's San Jose Division, the F2 and F3 factors would be 1.0, that is no discounting.

As formulated by PG&E, the F1 factor is determined as a function of a project's average energy production during a number of historically dry years in relationship to its long-term average energy production. PG&E requires that the F1 factor be determined on theoretical operation studies over the historical period 1928 through 1977.

While the District still lacks some of the hydrology data required, estimates were made of the F1 factor for each of the reservoir sites. The factors for the various reservoirs other than Anderson ranged from 0.76 to 0.81. Anderson had an F1 factor of 0.90. Based on the above, an average F1 factor of 0.80 was used for all reservoirs. In the economic analysis of each reservoir site, PG&E's October 1981 PURPA rate of $0.07104 per KWH was then discounted by 20 percent to a net rate of $0.05683 per KWH.

The use of the F factors is strongly being questioned by the California PUC and will probably result in their being modified or even eliminated, either of which would be in favor of the power seller. Nevertheless, as a conservative approach, the benefit/cost analyses of the various sites were based on a PG&E discounted rate of $0.05683 per KWH.

Escalation of Energy Prices

In the evaluation of energy sources, the general trend of most public agencies, including the Department of Water Resources, has been to escalate energy prices at a rate two percent (2%) per annum higher than the general rate of inflation. Figure 3 compares projected energy rates based on a 2% per year increase of energy above the general rate of inflation, to an extrapolation of recent PG&E projected PURPA rates. As required by the FERC regulation, utilities must provide quarterly projections of their marginal energy costs for the next 5 years. The projected PG&E rates have an initial escalation of about twenty-three percent per year, declining to a total of about eight percent per year by the mid-1980's and remaining at about eight percent per year through the life of the project. The two methods of inflating the price of energy have good correlation.

Table 3 presents a summary of the direct and indirect costs of each of the sites. Also shown are the benefit/cost ratios and payback periods at each of the sites based on the escalation of energy at 2% above the general rate of inflation and based on the projected PG&E PURPA rates. The payback period represents the number of years it would take the project to reach a positive accumulative cash flow. Table 3 also shows for each facility, the required net present day energy value needed for a project to have a benefit/cost ratio of 1.00. The above assumes that the rates would increase at 2% per year above the general rate of inflation.

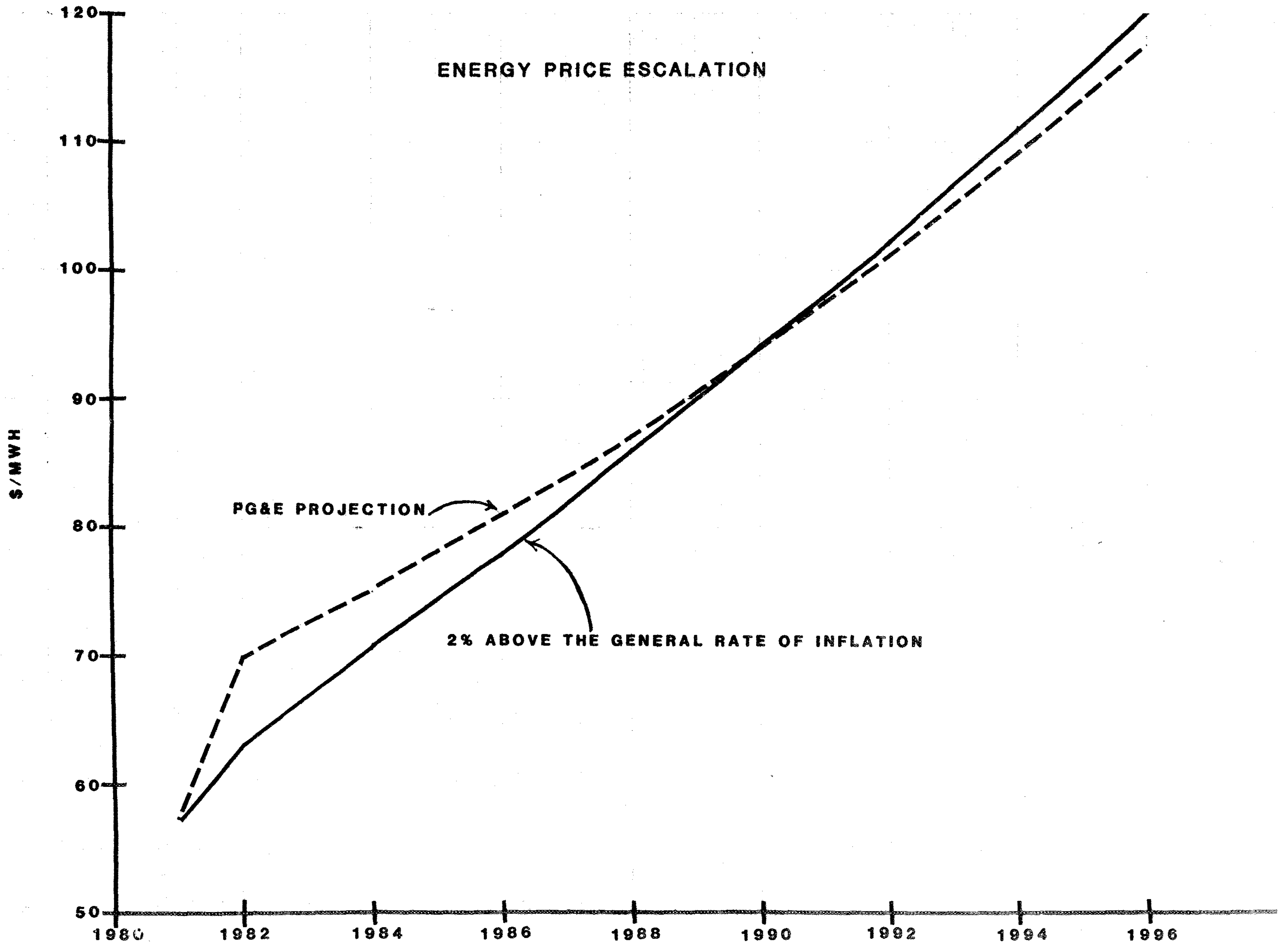

ENERGY PRICE ESCALATION
$/MWH
120
110
100
90
80
70
60
50
1980
1982
1984
1986
1988
1990
1992
1994
1996
PG&E PROJECTION
2% ABOVE THE GENERAL RATE OF INFLATION

Figure 3

TABLE 3

SUMMARY OF BENEFIT/COST ANALYSES

	Costs		Benefits				
			2% above Rate of Inflation		PG&E Projection		
Reservoir	Direct ($)	Indirect ($)	B/C Ratio	Payback (Yrs)	B/C Ratio	Payback (Yrs)	Rate for [1] B/C=1 $/KWH
Anderson	1,089,900	479,100	4.02	2	3.47	2	.0145
Calero	1,411,100	620,800	2.98	3	2.56	2	.0190
Lexington	1,355,600	596,400	1.72	20	1.48	22	.0330
Coyote	897,200	394,700	1.06	38	.91	--	.0535
Stevens Creek	840,300	369,700	0.48	–	.41	–	.120
Guadalupe	743,800	327,200	0.45	–	.38	–	.128
Almaden	727,800	320,200	0.30	–	.26	–	.180

---

[1] Rates based on energy escalation 2% above general rate of inflation.

Sensitivity Analysis

Small-scale hydroelectric generation is considered by many to be quite speculative at the present time. The boom in hydro could go bust if the U.S. Supreme Court agrees with a recent Mississippi District Court decision which struck down that portion of PURPA that forces utilities to buy locally produced hydropower at their avoided cost. Others feel that even if PURPA is struck down on the federal level, the California PUC would still require the California utilities to purchase energy at their avoided cost.

On the other hand, many consider hydro projects better than a gold mine "because gold runs out and hydro keeps producing revenue as long as the water keeps flowing". It is felt that energy will continue to inflate at rates much greater than the rate of inflation. In addition, PG&E's discount factors are expected to be modified or even eliminated by the CPUC in favor of the power developer.

In light of the many uncertainties, a sensitivity analysis was made on those projects which appear to have the greatest economic benefit. A sensitivity analysis allows one to evaluate those factors which are not clearly defined so that a more intelligent evaluation of a project can be made. The analysis shown on Table 4 indicates how the benefit/cost ratio is affected by variation in those parameters which are more uncertain. In each case, only one parameter was varied while all other parameter values were held at the base value.

Discussion of Results

The four parameters that have the greatest uncertainty in developing the benefit/cost ratios for the projects considered are:

- the rate at which capital would be borrowed
- the rate at which energy would be sold
- the escalation of the price of energy in the future
- the accuracy of the project's anticipated capital cost.

TABLE 4

SENSITIVITY ANALYSIS
B/C Ratio

Parameter Varied	PROPOSED SITES ANDERSON	CALERO	LEXINGTON	COYOTE
Bond Interest Rates (%)				
10	4.96	3.67	2.12	1.30
12*	4.02	2.98	1.72	1.06
14	3.28	2.42	1.40	0.86
Energy Escalation (%) (Above the general rate of inflation)				
0	2.89	2.14	1.24	0.76
1	3.39	2.51	1.45	0.89
2*	4.02	2.98	1.72	1.06
3	4.82	3.57	2.06	1.27
5	7.14	5.28	3.05	1.88
Price of Energy ($/KWH)				
.0400	2.83	2.09	1.21	0.74
.0500	3.54	2.62	1.51	0.93
.0568*	4.02	2.98	1.72	1.06
.0650	4.60	3.40	1.97	1.21
.0710	5.03	3.72	2.15	1.32
Project Cost (% of Estimate)				
80	5.03	3.72	2.15	1.32
90	4.47	3.31	1.91	1.17
100*	4.02	2.98	1.72	1.06
125	3.22	2.38	1.38	0.85
150	2.68	1.98	1.15	0.70
O&M Cost (% of Project Cost)				
.60	4.49	3.32	1.92	1.18
.90	4.24	3.14	1.81	1.11
1.2*	4.02	2.98	1.72	1.06
2.4	3.33	2.47	1.42	0.88
4.5	2.56	1.90	1.10	0.67
Energy Production (% of Estimate)				
75	3.02	2.23	1.29	0.79
90	3.62	2.68	1.55	0.95
100*	4.02	2.98	1.72	1.06
110	4.42	3.27	1.89	1.16
125	5.03	3.72	2.15	1.32

* Figure Used in Basic Analysis

At the current maximum allowable bond rate of 12%, the four recommended projects Anderson, Calero, Lexington and Coyote have benefit/cost ratios greater than one. Even if bond rates increased to 14%, Anderson, Calero, and Lexington would still have B/C's greater than one. Coyote's B/C would be 0.86.

If all of the advantageous legislation concerning hydroelectric power, such as PURPA, were repealed, the District would have to negotiate with PG&E and settle on a rate for the sale of its energy. Using 40 mills/KWH as this negotiated rate, which is 65% of the current rate at which PG&E sells energy to municipalities, Anderson, Calero and Lexington would have a benefit/cost ratio (B/C) greater than one and Coyote's B/C would be 0.74. Figures 4 and 5 illustrate this over a wide range of energy rates.

During the last twenty years electricity rates have risen 1.1 percent above the general rate of inflation and over the last five years these rates have escalated 5.7 percent above the general rate of inflation. Under the scenario where energy escalates only at the rate of general inflation, Anderson, Calero and Lexington would have a B/C greater than one and Coyote's B/C would be 0.76.

Uncertainty always exists when estimating project costs. If the capital cost of the projects were to overrun the estimated cost by 50%, Anderson, Calero, and Lexington would still have a B/C greater than one and Coyote's B/C would be 0.70.

All in all, it is felt that at least the proposed Anderson, Calero and Lexington projects should be further investigated.

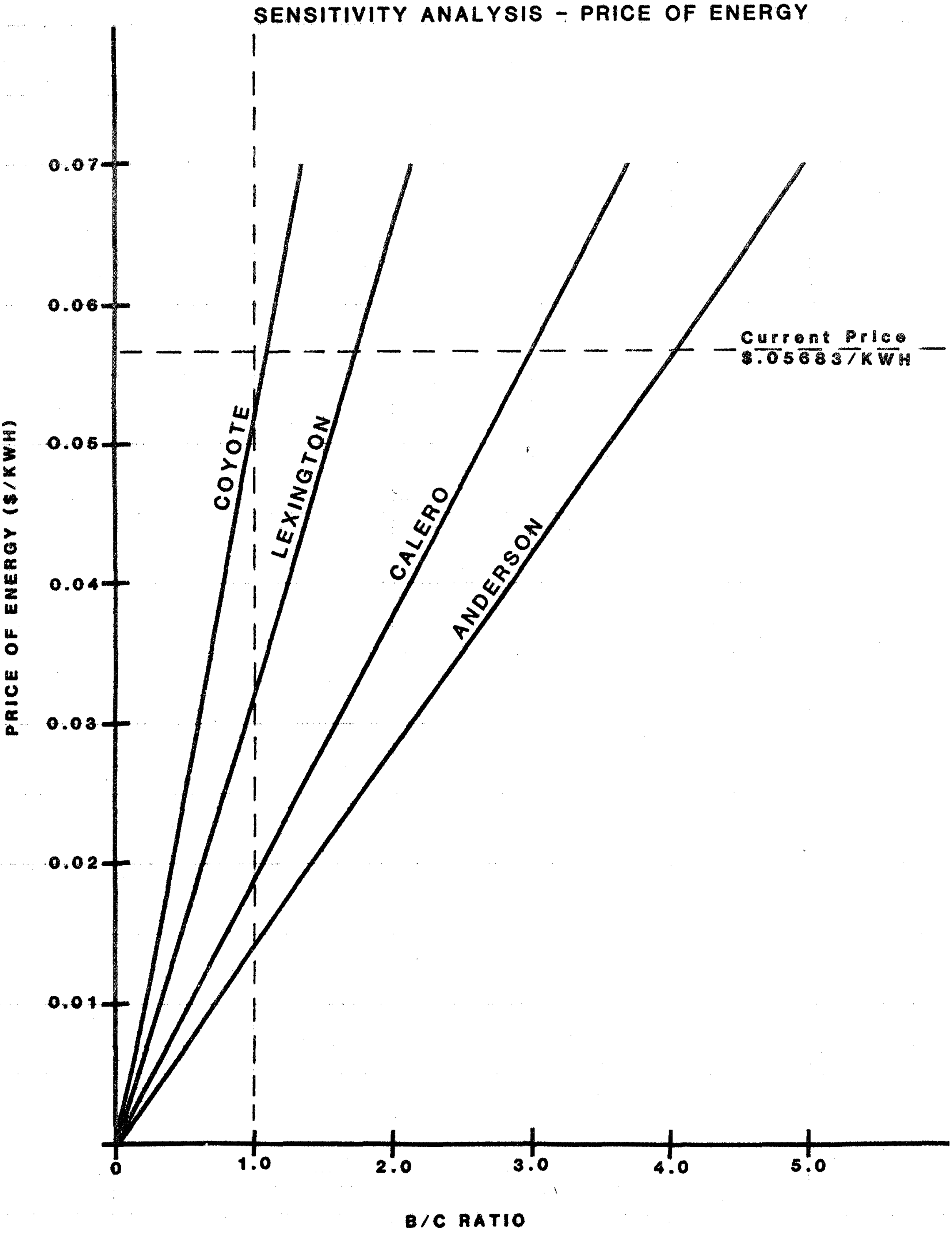

SENSITIVITY ANALYSIS - PRICE OF ENERGY
PRICE OF ENERGY ($/KWH)
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
1.0
2.0
3.0
4.0
5.0
B/C RATIO
COYOTE
LEXINGTON
CALERO
ANDERSON
Current Price
$.05683/KWH

Figure 4

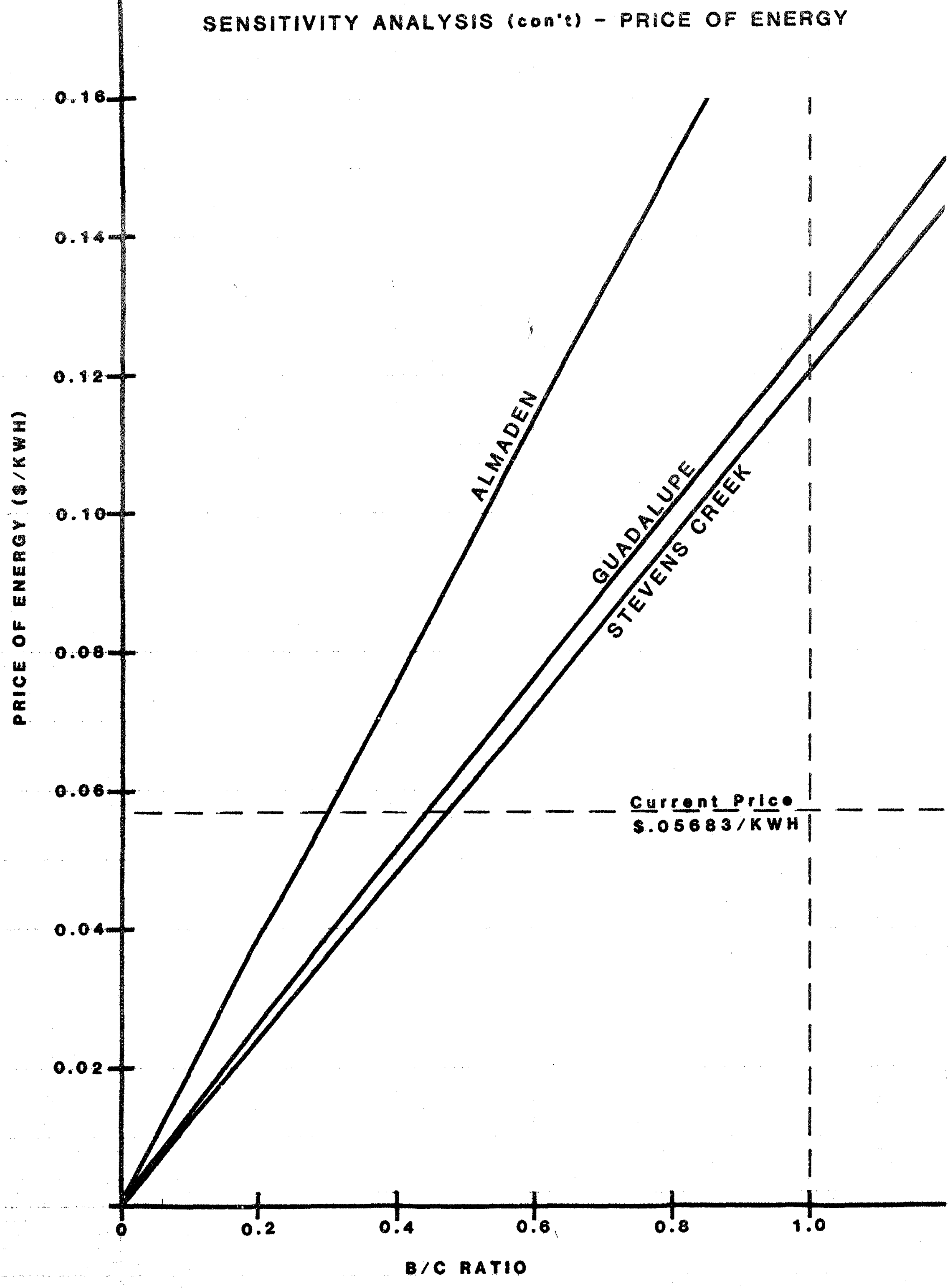

SENSITIVITY ANALYSIS (con't) - PRICE OF ENERGY
PRICE OF ENERGY ($/KWH)
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0
0.2
0.4
0.6
0.8
1.0
B/C RATIO
ALMADEN
GUADALUPE
STEVENS CREEK
Current Price
$.05683/KWH

Figure 5

Use of District Turbine

A possible cost-saving option examined in this study was the use of a District-owned Hitachi-built 900 KW turbine. The use of this turbine was studied at the Lexington and Coyote sites since head and flow characteristics of the reservoirs seem best suited to that of the turbine. Economic analyses were performed on Lexington and Coyote with the reduced costs of owning a turbine, the results of which are presented in Appendix H.

The turbine proved most beneficial at Lexington Reservoir. It increased its benefit/cost ratio by 27 percent, though the average annual energy production would decrease by about 13 percent, in comparison to the selection of the most optimum unit for the site.

At Coyote Reservoir, the use of the District turbine increased the benefit/cost ratio by less than eight percent, while decreasing the average annual energy production by 25 percent in comparison to the selection of the most optimum unit for the site.

FINANCIAL ANALYSIS

Sources of financing available to the District for this type of project include pay-as-you-go, bonds, and financial aid from a public or private agency which might wish to buy the power or which may wish to share in the revenues. While a number of federal and state assistance programs exist, mainly for conducting feasibility studies, these programs have received little or no funding. The financial alternatives are briefly outlined below.

Pay-As-You-Go Financing

This type of financing is the accumulation of funds from income, before construction begins, to build a project.

Bonds

Bonds offer an advantage for financing in that the capital cost of a facility is amortized over a period of time once the facility is constructed. The two types of bonds currently available to the District are 1941 Revenue Bond Act bonds and nonprofit corporation lease-purchase revenue bonds. Since the passage of Proposition 13, general obligation bonds are no longer considered a potential method of financing.

The 1941 Revenue Bond Act requires a majority voter approval and provides long-term financing. Currently, state law limits the interest rate on the bonds to 12 percent and the repayment period to 40 years. A major consideration of these bonds is the debt service coverage requirement. The ratio of net operating revenue should be at least 1.5 times actual bond service requirements to provide adequate security and coverage. As a practical matter, the coverage factor should be closer to 2.0 in order to secure better bond ratings and better interest rates. For a major construction program, coverage requirements can result in the generation of surplus cash; consequently, it is often advisable to construct some of the facilities on a pay-as-you-go basis with the additional cash generated to meet coverage requirements.

Nonprofit corporation lease-purchase revenue bonds are a financing vehicle available to the District as a public agency. They provide a nonvoted, multi-purpose, open-ended source of financing. Under this method, a corporation is formed under general law with a limited, specific purpose of acting as a landlord to build or acquire public facilities for a public agency. The nonprofit corporation, by meeting IRS criteria, can issue tax exempt bonds to finance facilities. The arrangement between the public agency and the nonprofit corporation must be set up as a valid lease which serves as collateral to the investors.

The nonprofit corporation has been widely used throughout California for the construction of public buildings, sewer and water systems and other types of facilities. Under current law, competitive bidding is required to issue the bonds and there is a 60 day referendum period to make sure that the public interest is served. Recent interest rates for nonprofit corporation bonds indicate that with reasonable security in the payment of debt service, nonprofit corporation financing may be very similar in cost to the 1941 Act for revenue bonds. Coverage requirements to the District under the nonprofit corporation arrangement would be similar to coverage requirements of the 1941 Revenue Bond Act.

Outside Agencies

Two additional alternatives for financing are through public or private agencies. A public or private agency interested in purchasing power may wish to help finance a small hydroelectric plant. A private agency may also wish to help finance a hydroelectric project in return for a percentage of the revenues.

PROCEDURE FOR SITE LICENSING

It generally takes a minimum of 36 months to develop a small hydroelectric project from reconnaissance survey to operation. An important step in the process is securing the required permits and licenses from the Federal Energy Regulatory Commission (FERC) and the State Water Resources Control Board.

Federal Energy Regulatory Commission

The Federal Power Act gives the Federal Energy Regulatory Commission authority to regulate certain aspects of hydroelectric development throughout the United States. The Federal Power Act requires the Commission to license any hydropower plant which:

(1) is located on Federal land,

(2) is located in or uses water from a navigable stream,

(3) uses water impounded by a Federal dam,

(4) produces power which affects interstate commerce.

The Commission issues permits and licenses. A preliminary permit is issued to enable the applicant to maintain priority to a site for hydropower development while completing necessary studies and preparing an application for license. However, a permit is not a prerequisite for filing an application for license. A permit does not authorize construction. It has, by law, a maximum term of three years. Licences authorize construction, operation and maintenance of a project. They are issued for periods not to exceed fifty years.

There is no minimum capacity specified in the Act below which a project would be exempt from licensing. The necessity for licensing is based entirely upon jurisdictional status as defined above. There is no fee for filing applications for permits or licenses for hydro projects. Annual charges for operation of projects under licenses are based upon the annual generation at the project, the acreage of any federal lands occupied and, where applicable, headwater benefits. Project facilities and operations are inspected by Commission engineers at least once a month during construction and at least annually during the operation of a project.

Applications for Preliminary Permits

An application for preliminary permit is comprised of an initial statement and four exhibits. The initial statement identifies the applicant and gives the name and location of the proposed project and the proposed term of permit. The first exhibit contains a description of the proposed project. The second exhibit includes a study plan and work schedule for the investigations and other activities to be carried out under the permit. The third exhibit consists of a statement of costs and financing to inform the Commission as to the financial ability of the applicant to carry out the necessary activities under the permit. Any tentative information that is available concerning the ultimate market for project power should also be provided. The fourth exhibit is a map or maps showing the geographical location of the project, the physical interrelationships of its principal features and a proposed project boundary.

Applications for Licenses

Since all of the District's potential hydroelectric projects would be 1.5 MW or less in capacity, the District should qualify for licensing under either of the following:

1. Applications as a Minor Project

This license application would be for a project having 1.5 MW or less in capacity. This application requires information about the applicant, the project location and description, the proposed mode of operation (run-of-river or peaking), U. S. lands involved and the date construction will begin and end if a license is issued. Required supplements to the application form include a report describing the environmental setting in the project area, environmental impacts expected from the project and measures proposed to mitigate adverse environmental impacts. Written comments from federal and state agencies with affected resource management responsibilities must be obtained and attached to the application. Simple maps locating the project and showing arrangement of project facilities are also required.

2. Exempted Project:

The Commission has the discretion to exempt projects with installed capacities not over 5 MW on a case-by-case basis. Such projects must utilize the water power potential of an existing dam unless the project uses a "natural water feature" that does not require the creation of a dam or man-made impoundment. Such projects must comply with environmental requirements applied by the National Environmental Policy Act, the Fish and Wildlife Coordination Act, the Endangered Species Act, and the consultation provisions in Section 30 of the Federal Power Act. Only a person who has sufficient property interests to develop the site may apply for the exemption. All, but not part, of a currently licensed project is exemptible. The application must propose to install new capacity or develop capacity not previously being used. Projects may include federal lands, but cannot include federal dams. All exemptions granted will include five standard conditions and any further conditions deemed necessary by the Commission.

The application package must include an introductory statement and Exhibits A, B, E, and G. The introductory statement identifies the applicant and the project and documentary evidence showing that the applicant has the required real property interests in private lands in the project. Exhibit A contains a description of the facility and the proposed mode of operation. Exhibit B is a general location map showing project features, affected streams or water bodies, and identifying real property interests in tracts of lands involved in the project. Exhibit E is an environmental report containing a description of the environmental setting of the project, the expected environmental impacts and documentation of consultation efforts with relevant fish and wildlife agencies. Exhibit G is a set of drawings including plan, elevation and section views of the power plant, existing dams, diversion structures, and any other principal structures.

If the Commission does not take specific action on the exemption application within 120 days after the applicant has been notified that its application is accepted for filing, the exemption will become effective by operation of law.

State Water Resources Control Board

The Division of Water Rights of the State Water Resources Control Board is involved in small hydroelectric projects in essentially three separate ways:

1. Whenever development of a small hydroelectric project will entail a new appropriation of water, a water right application must be filed and a permit must be obtained before the operation of the project commences.

2. If the water used through the small hydro plant is strictly incidental to the movement of water under permits and licenses, a petition for change may be filed. Use of the hydroelectric plant is not authorized until a change order has been issued by the Board.

3. Compliance with the California Environmental Quality Act (CEQA) of 1970 is necessary.

Since the District will continue to operate its reservoirs for maximum conservation, as authorized under its various existing licenses, and the operation of the turbines will be strictly incidental to the movement of water, only a petition for change should be required.

In its petition for change in its various water right applications, the District will have to satisfactorily resolve all fish and wildlife impact issues with the State Department of Fish and Game related to the hydroelectric project. In its "General Guidelines for Hydroelectric Development", the Department of Fish and Game has stated that the addition of hydroelectricity at an existing dam site need not necessarily enhance fish and wildlife if the anticipated flow regime of the project is not changed. On the other hand, Fish and Game has stated that it will seek fish and wildlife enhancement within the capability of the project.

When considering water rights, the State Water Resources Control Board has grouped new hydroelectric plants into three categories based on their potential to cause significant adverse impacts and, thus, their desirability in being constructed. These categories are as follows, in order of desirability from an environmental standpoint:

1. Retrofit power plants at existing dams, canals, or conduits where the streamflow regime will not be changed and there will be no signficiant adverse impacts.

2. Small "run-of-the-river" plants and 5 MW capacity or less where water is not being impounded during times of high flow to generate power and there will be no signficiant adverse impacts.

3. All other projects not in Category 1 or 2, including conventional power projects.

All of the District's proposed hydroelectric projects would be in Category 1.

Because of the recognized need for additional power in the State and the administration's support of small scale hydro project development, the Division's policy, related to Category 1 projects, is to expedite the processing of the water right applications or petitions. The District will not be required by the California Energy Commission (CEC) to show a need for the power to be generated unless protests are filed that cannot be resolved.

The Board has stated that it will give all projects a thorough environmental review including, but not limited to, an assessment of transmission line impacts, if applicable, and water conservation measures to be applied if consumptive use is part of the project. If the sponsoring agency is a public agency, it will be the lead agency for preparation of environmental documents under CEQA. If no application or petition is necessary, the Board's duties are merely to review and comment on the environmental documents. When an application or petition is filed, the Board must consider the environmental documents before it may approve the project, unless the project has been declared exempt.

CONCLUSIONS AND RECOMMENDATIONS

Seven reservoir sites in Santa Clara County (one in conjunction with the Calero Pipeline) have been examined in this report to assess the economic feasibility of installing small scale hydroelectric generation facilities. On the basis of current preliminary cost data for small scale hydro and the current price of energy, four sites appear economically feasible at this time. Their benefit/cost ratios are greater than one, indicating minimal economic risk in constructing the facilities.

Specific recommendations are outlined below for the sites with the greatest benefit/cost ratios. However, it is recommended that all of the remaining sites be kept on active file for periodic review as energy costs and construction costs change with time, because even smaller scale plants may become economically feasible within the next few years or so. Because of the many financing options available to the District, it is recommended that an in-depth financial analysis be made of the various options.

Anderson Reservoir

The study showed this site to have the greatest economic benefit, with a benefit/cost ratio of 4.02 in the basic analysis. As it can be seen in the sensitivity analysis, the project maintains a benefit/cost ratio signficantly greater than one over a wide range of possible market conditions and uncertainties in projected costs. Thus, this site carries minimal risks. It is recommended that immediate action be taken to obtain a preliminary permit from FERC to secure priority development rights to the site. This will give the District, as the developer, up to 36 months priority over other applicants. During this time, a final feasibility study should be performed and formal licensing procedures initiated. Without timely action, the District could lose its development rights, as well as losing benefits from the production of electricity.

Calero Reservoir

Analysis of the development of hydroelectric facilities at the Calero site also indicates a high benefit/cost ratio with minimal risk. It is recommended that action be taken as soon as possible to secure development rights and to determine the necessary licensing requirements at this site. The licensing may be somewhat more involved because the facilities will generate power both from a pipeline and from reservoir outflow. Further studies will be required to evaluate the feasibility of generating power prior to the construction of the proposed Calero Pipeline.

Lexington Reservoir

Lexington is the third site at which development of hydroelectric facilities is economically justified at the present time. Priority development rights should be secured as soon as possible by application to FERC. In order to determine the actual cost and the amount of work required to handle pressurized flow in the outlet works, an investigation will be required. This could be done during the summer of 1982 when the reservoir will be drawn down to replace valves on the outlet works. Unless the costs to place a steel liner to allow pressurized flow prove prohibitive, final feasibility studies and licensing procedures should begin as soon as the investigation is completed.

At Lexington Reservoir, it is also recommended that further investigation of the use of the District turbine be performed during the final feasibility study. Use of this turbine may significantly increase the attractiveness of the project.

Coyote Reservoir

The fourth site which appears economically justified at this time is Coyote, with a benefit/cost ratio of 1.06. It is recommended that this site, along with the three previous sites, be acted on immediately and preliminary permits obtained as soon as possible. In the final feasibility study, the use of the District turbine should be examined to determine whether or not it would actually increase the attractiveness of the Coyote project.

In review, preliminary permits should be obtained as soon as possible for the Anderson, Calero, Lexington and Coyote sites. This will give the District enough time to perform final feasibility and financial studies and decide if it wishes to proceed with requests for licensing. Also, by obtaining preliminary permits for the remaining sites, the District can secure priority development rights to develop the sites if they become economically beneficial.

APPENDIX A
ALMADEN SITE

TABLE A1: PROJECT DATA: ALMADEN

Description	Unit	Project Data	Remarks
General			
Location		S of New Almaden	
Cost Zone Coefficient		1	
Tributary Creek		Alamitos Creek	
Drainage Area	acre	7,680	
Design Capacity	Ac-ft	1,780	
Year dam completed		1935	
Head Data:			
Headwater Elevation:			
Maximum	ft	613	
Minimum	ft	550	
Tailwater Elevation at Design Discharge	ft	505	
Gross Head:			
Maximum	ft	113	
Minimum	ft	50	
Design	ft	95	
Design Net Head	ft	90	
Turbine:			
Type		Horizontal Francis	
Design Discharge	cfs	15	
Unit Capacity	kW	95	
Waterways:			
Intake Structures Required	No	None	
Penstock:			
Length:			
Main	ft	50	
Branch	ft	-	
Bifurcation Required	No	1	
Maximum Velocity	ft/sec	9.0	
Diameter	ft	1.5	
Bypass Structure Required	No	1	
Bypass Discharge	cfs	250	
Tailrace Length	ft	50	
Transmission Line:			
Voltage	kV	13.8	
Capacity	MW	0.15	
Length	mile	1	

TABLE A2: COST COMPILATION: ALMADEN

Description	Unit	Quantity	Unit Cost $	Amount April 1979 $	Cost Indexes 1979 April	Cost Indexes 1981 July	Escalated Amount 1981 $
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	8,000	8,000	2.34	2.92	10,000
Bifurcation	No.	1	8,000	8,000	2.34	2.92	10,000
SUBTOTAL							25,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS		370,000	370,000	2.45	3.14	474,200
Equipment Adjustments:	LS						
SUBTOTAL UNIT							474,200
Bypass Structure	LS		75,000	75,000	2.34	2.92	93,600
Tailrace	LF	50	10	500	2.39	3.04	600
Switchyard:							
Civil Features	LS		9,000	9,000	2.40	2.94	11,000
Equipment	LS		66,000	66,000	2.40	2.94	80,900
SUBTOTAL							660,300
3. Special Costs:							
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							685,900
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					13,700
SUBTOTAL							699,600
5. Transmission Line:							
Line x.9 Length Factor	mile	1	26,000	23,400	2.69	3.19	27,700
6. TOTAL							727,300

TABLE A3: PROJECT COST SUMMARY: ALMADEN

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	25,600.
2.	Power Plant	660,300.
3.	Special Structures	-
4.	Existing Facilities	-
5.	General Costs	13,700.
6.	Transmission Line	27,700.
7.	TOTAL DIRECT COST	727,300.
8.	Contingencies (20%)	145,500.
9.	Sub-Total	872,800.
10.	Engineering, Administration and Construction Management (20%)	174,600.
11.	TOTAL CONSTRUCTION COST:	$1,047,300.

TABLE A4

ALMADEN DAM

BASE ENERGY PRICE= 71.04 MILLS/KWH, F1 DISCOUNT FACTOR= 0.80
ENERGY RATE USED= 56.83 MILLS/KWH, ANNUAL O&M 1.20 % OF CAPITAL COST
CAPITAL COST ($1000) = 1048.0, ANNUAL ENERGY PRODUCTION = 230.0 MWH

YEAR	INT. RATE (%)	DEBT SERVICE ($1000)	INFL RATE (%)	O&M COSTS ($1000)	ENERGY ESC RATE (%)	ENERGY INCOME ($1000)	PW FACTOR	PRESENT VALUE COSTS ($1000)	PRESENT VALUE BENEFITS ($1000)
1982	12.00	140	9.70	13	11.70	14	0.893	137	13
1983	12.00	140	9.50	15	11.50	16	0.797	123	12
1984	12.00	140	9.10	16	11.10	18	0.712	111	12
1985	12.00	140	8.70	17	10.70	20	0.636	100	12
1986	12.00	140	8.30	19	10.30	22	0.567	90	12
1987	12.00	140	7.90	20	9.90	24	0.507	81	12
1988	12.00	140	7.50	22	9.50	26	0.452	73	12
1989	12.00	140	7.10	24	9.10	28	0.404	66	11
1990	12.00	140	6.70	25	8.70	31	0.361	59	11
1991	12.00	140	6.69	27	8.69	34	0.322	54	11
1992	12.00	140	6.68	29	8.68	37	0.287	48	10
1993	12.00	140	6.67	31	8.67	40	0.257	44	10
1994	12.00	140	6.66	33	8.66	43	0.229	39	10
1995	12.00	140	6.65	35	8.65	47	0.205	35	9
1996	12.00	140	6.65	37	8.65	51	0.183	32	9
1997	12.00	140	6.64	40	8.64	56	0.163	29	9
1998	12.00	140	6.63	43	8.63	61	0.146	26	8
1999	12.00	140	6.62	45	8.62	66	0.130	24	8
2000	12.00	140	6.61	48	8.61	72	0.116	21	8
2001	12.00	140	6.60	52	8.60	78	0.104	19	8
2002	7.60		6.60	55	8.60	85	0.096	5	8
2003	7.60		6.60	59	8.60	92	0.090	5	8
2004	7.60		6.60	63	8.60	100	0.083	5	8
2005	7.60		6.60	67	8.60	109	0.077	5	8
2006	7.60		6.60	71	8.60	118	0.072	5	8
2007	7.60		6.60	76	8.60	128	0.067	5	8
2008	7.60		6.60	81	8.60	139	0.062	5	8
2009	7.60		6.60	87	8.60	151	0.058	5	8
2010	7.60		6.60	92	8.60	164	0.054	4	8
2011	7.60		6.60	98	8.60	179	0.050	4	8
2012	7.60		6.60	105	8.60	194	0.046	4	9
2013	7.60		6.60	112	8.60	211	0.043	4	9
2014	7.60		6.60	119	8.60	229	0.040	4	9
2015	7.60		6.60	127	8.60	249	0.037	4	9
2016	7.60		6.60	136	8.60	270	0.035	4	9
2017	7.60		6.60	145	8.60	293	0.032	4	9
2018	7.60		6.60	154	8.60	318	0.030	4	9
2019	7.60		6.60	164	8.60	346	0.028	4	9
2020	7.60		6.60	175	8.60	376	0.026	4	9
2021	7.60		6.60	187	8.60	408	0.024	4	9
						TOTAL		1321	395

BENEFIT COST RATIO = 395 / 1321 = 0.30

APPENDIX B
ANDERSON SITE

TABLE B1: PROJECT DATA: ANDERSON

Description	Unit	Project Data	Remarks
General			
Location		2 mi East of Morgan Hill	
Cost Zone Coefficient		1	
Tributary Creek		Coyote Creek	
Drainage Area	acre	123,300	
Design Capacity	Ac-ft	91,200	
Year dam completed		1950	
Head Data:			
Headwater Elevation:			
Maximum	ft	635	
Minimum	ft	535	
Tailwater Elevation at Design Discharge	ft	410	
Gross Head:			
Maximum	ft	225	
Minimum	ft	125	
Design	ft	175	
Design Net Head	ft	170	
Turbine:			
Type		Horizontal Francis	
Design Discharge	cfs	80	
Unit Capacity	kW	960	
Waterways:			
Intake Structures Required	No	None	
Penstock:			
Length:			
Main	ft	50	
Branch	ft	-	
Bifurcation Required	No	1	
Maximum Velocity	ft/sec	17	
Diameter	ft	2.5	
Bypass Structure Required	No	1	
Bypass Discharge	cfs	570	
Tailrace Length	ft	50	
Transmission Line:			
Voltage	kV	13.8	
Capacity	MW	1.0	
Length	mile	1.0	

TABLE B2: COST COMPILATION: ANDERSON

Description	Unit	Quantity	Unit Cost $	Amount April 1979 $	Cost Indexes 1979 April	Cost Indexes 1981 July	Escalated Amount 1981 $
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	20,000	20,000	2.34	2.92	25,000
Bifurcation	No.	1	12,000	12,000	2.34	2.92	15,000
SUBTOTAL							45,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS		540,000	540,000	2.45	3.14	692,100
Equipment Adjustments:	LS						
SUBTOTAL UNIT							692,100
Bypass Structure	LS	1	160,000	160,000	2.34	2.92	199,700
Tailrace	LF	50	35	1,750	2.39	3.04	2,200
Switchyard:							
Civil Features	LS		10,500	10,500	2.40	2.94	12,900
Equipment	LS		68,000	68,000	2.40	2.94	83,300
SUBTOTAL							988,000
3. Special Costs:							
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							1,033,600
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					20,700
SUBTOTAL							1,054,300
5. Transmission Line:							
Line x.9 Length Factor	mile	1	30,000	27,000	2.69	3.19	32,400
6. TOTAL							1,086,300

TABLE B3: PROJECT COST SUMMARY: ANDERSON

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	45,600.
2.	Power Plant	988,000.
3.	Special Structures	–
4.	Existing Facilities	–
5.	General Costs	20,700.
6.	Transmission Line	32,000.
7.	TOTAL DIRECT COST	1,086,300.
8.	Contingencies (20%)	217,300.
9.	Sub-Total	1,303,600.
10.	Engineering, Administration and Construction Management (20%)	260,700.
11.	TOTAL CONSTRUCTION COST:	$1,564,300.

TABLE B4

ANDERSON DAM

BASE ENERGY PRICE= 71,04 MILLS/KWH, F1 DISCOUNT FACTOR= 0,80
ENERGY RATE USED= 56,83 MILLS/KWH, ANNUAL O&M 1,20 % OF CAPITAL COST
CAPITAL COST ($1000) = 1568,0, ANNUAL ENERGY PRODUCTION = 4621,0 MWH

YEAR	INT. RATE (%)	DEBT SERVICE ($1000)	INFL RATE (%)	O&M COSTS ($1000)	ENERGY ESC RATE (%)	ENERGY INCOME ($1000)	PW FACTOR	PRESENT VALUE COSTS ($1000)	PRESENT VALUE BENEFITS ($1000)
1982	12,00	209	9,70	20	11,70	293	0,893	205	261
1983	12,00	209	9,50	22	11,50	327	0,797	185	260
1984	12,00	209	9,10	24	11,10	363	0,712	166	258
1985	12,00	209	8,70	26	10,70	402	0,636	150	255
1986	12,00	209	8,30	29	10,30	443	0,567	135	251
1987	12,00	209	7,90	31	9,90	487	0,507	122	247
1988	12,00	209	7,50	33	9,50	533	0,452	110	241
1989	12,00	209	7,10	36	9,10	582	0,404	99	235
1990	12,00	209	6,70	38	8,70	633	0,361	89	228
1991	12,00	209	6,69	41	8,69	688	0,322	80	221
1992	12,00	209	6,68	43	8,68	748	0,287	72	215
1993	12,00	209	6,67	46	8,67	812	0,257	65	208
1994	12,00	209	6,66	49	8,66	883	0,229	59	202
1995	12,00	209	6,65	53	8,65	959	0,205	53	196
1996	12,00	209	6,65	56	8,65	1042	0,183	48	190
1997	12,00	209	6,64	60	8,64	1132	0,163	44	184
1998	12,00	209	6,63	64	8,63	1230	0,146	39	179
1999	12,00	209	6,62	68	8,62	1336	0,130	36	173
2000	12,00	209	6,61	73	8,61	1451	0,116	32	168
2001	12,00	209	6,60	78	8,60	1576	0,104	29	163
2002	7,60		6,60	83	8,60	1712	0,096	8	164
2003	7,60		6,60	88	8,60	1859	0,090	7	166
2004	7,60		6,60	94	8,60	2019	0,083	7	168
2005	7,60		6,60	100	8,60	2192	0,077	7	169
2006	7,60		6,60	107	8,60	2381	0,072	7	171
2007	7,60		6,60	114	8,60	2586	0,067	7	172
2008	7,60		6,60	122	8,60	2808	0,062	7	174
2009	7,60		6,60	130	8,60	3050	0,058	7	175
2010	7,60		6,60	138	8,60	3312	0,054	7	177
2011	7,60		6,60	147	8,60	3597	0,050	7	179
2012	7,60		6,60	157	8,60	3906	0,046	7	180
2013	7,60		6,60	168	8,60	4242	0,043	7	182
2014	7,60		6,60	179	8,60	4607	0,040	7	184
2015	7,60		6,60	191	8,60	5003	0,037	7	186
2016	7,60		6,60	203	8,60	5434	0,035	7	187
2017	7,60		6,60	217	8,60	5901	0,032	6	189
2018	7,60		6,60	231	8,60	6409	0,030	6	191
2019	7,60		6,60	246	8,60	6960	0,028	6	193
2020	7,60		6,60	263	8,60	7558	0,026	6	194
2021	7,60		6,60	280	8,60	8208	0,024	6	196
						TOTAL		1977	7952

BENEFIT COST RATIO = 7952 / 1977 = 4,02

TOTAL BENEFITS EXCEED TOTAL COSTS BY YEAR 1983

APPENDIX C
CALERO SITE

TABLE C1: PROJECT DATA: CALERO

Description	Unit	Project Data	Remarks
General			
Location		Adj to McKean Rd, Calero Valley	
Cost Zone Coefficient		1	
Tributary Creek		Calero Creek	
Drainage Area	acre	4,480	
Design Capacity	Ac-ft	10,160	
Year dam completed		1935	
Head Data:			
Headwater Elevation:			
Maximum	ft	110	Aver. excess head in P.L.
Minimum	ft		
Tailwater Elevation at Design Discharge	ft	390	
Gross Head:			
Maximum	ft	173	
Minimum	ft	58	
Design	ft	115	
Design Net Head	ft	110	
Turbine:			
Type		2	Horizontal Francis
Design Discharge	cfs	85 & 100	
Unit Capacity	kW	660 + 777 = 1437	
Waterways:			
Intake Structures Required	No	None	
Penstock:			
Length:			
Main	ft	100	
Branch	ft	50	
Bifurcation Required	No	2	
Maximum Velocity	ft/sec	12	
Diameter	ft	3.33 = 40"	
Bypass Structure Required	No	1	
Bypass Discharge	cfs	200	
Tailrace Length	ft	50	
Transmission Line:			
Voltage	kV	13.8	
Capacity	MW	1.5	
Length	mile	1	

TABLE C2: COST COMPILATION: CALERO

Description	Unit	Quantity	Unit Cost $	Amount April 1979 $	Cost Indexes 1979 April	Cost Indexes 1981 July	Escalated Amount 1981 $
1. Penstock:		50	120				
Penstock	LF	150 100	90	15,000	2.61	3.27	18,800
Valving	No.	2	20,000	40,000	2.34	2.92	50,000
Bifurcation	No.	2	12,000	24,000	2.34	2.92	29,900
SUBTOTAL							98,700
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS		761,250	761,250	2.45	3.14	975,600
Equipment Adjustments:	LS						
SUBTOTAL UNIT							975,600
Bypass Structure	LS		88,000	88,000	2.34	2.92	109,800
Tailrace	LF	50	16	800	2.39	3.04	1,000
Switchyard:							
Civil Features	LS			133,800	2.40	2.94	163,900
Equipment	LS						1,249,300
SUBTOTAL							
3. Special Costs:							
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							1,348,000
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					27,000
SUBTOTAL							1,375,000
5. Transmission Line:							
Line x.9 Length Factor	mile	1	33,000	29,700	2.69	3.19	35,200
6. TOTAL							1,410,200

TABLE C3: PROJECT COST SUMMARY: CALERO

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	98,700.
2.	Power Plant	1,249,300.
3.	Special Structures	–
4.	Existing Facilities	–
5.	General Costs	27,000.
6.	Transmission Line	35,200.
7.	TOTAL DIRECT COST	1,410,200.
8.	Contingencies (20%)	282,000.
9.	Sub-Total	1,692,200.
10.	Engineering, Administration and Construction Management (20%)	338,500.
11.	TOTAL CONSTRUCTION COST:	$2,030,700.

TABLE C4

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                        CALERO DAM AND PIPELINE
BASE ENERGY PRICE= 71.04 MILLS/KWH, PI DISCOUNT FACTOR=  0.80
ENERGY RATE USED= 56.83 MILLS/KWH,  ANNUAL O&M  1.20 % OF CAPITAL COST
CAPITAL COST ($1000) =  2032.0, ANNUAL ENERGY PRODUCTION = 4430.0 MWH

YEAR  INT.   DEBT    INFL   O&M    ENERGY ENERGY   PW    PRESENT  PRESENT
      RATE SERVICE   RATE  COSTS    ESC   INCOME FACTOR   VALUE    VALUE
                                    RATE                  COSTS   BENEFITS
       (%)  ($1000)  (%)  ($1000)   (%)  ($1000)         ($1000)  ($1000)
1982  12.00   272    9.70     26   11.70    281   0.893    266      251
1983  12.00   272    9.50     29   11.50    313   0.797    240      249
1984  12.00   272    9.10     31   11.10    348   0.712    216      247
1985  12.00   272    8.70     34   10.70    385   0.636    194      245
1986  12.00   272    8.30     37   10.30    425   0.567    175      241
1987  12.00   272    7.90     40    9.90    467   0.507    158      236
1988  12.00   272    7.50     43    9.50    511   0.452    142      231
1989  12.00   272    7.10     46    9.10    558   0.404    128      225
1990  12.00   272    6.70     49    8.70    607   0.361    116      218
1991  12.00   272    6.69     53    8.69    659   0.322    104      212
1992  12.00   272    6.68     56    8.68    717   0.287     94      206
1993  12.00   272    6.67     60    8.67    779   0.257     85      200
1994  12.00   272    6.66     64    8.66    846   0.229     77      194
1995  12.00   272    6.65     68    8.65    920   0.205     69      188
1996  12.00   272    6.65     73    8.65    999   0.183     63      182
1997  12.00   272    6.64     78    8.64   1085   0.163     57      177
1998  12.00   272    6.63     83    8.63   1179   0.146     51      171
1999  12.00   272    6.62     89    8.62   1281   0.130     46      166
2000  12.00   272    6.61     94    8.61   1391   0.116     42      161
2001  12.00   272    6.60    101    8.60   1511   0.104     38      156
2002   7.60          6.60    107    8.60   1641   0.096     10      158
2003   7.60          6.60    114    8.60   1782   0.090     10      159
2004   7.60          6.60    122    8.60   1935   0.083     10      161
2005   7.60          6.60    130    8.60   2102   0.077     10      162
2006   7.60          6.60    139    8.60   2282   0.072     10      164
2007   7.60          6.60    148    8.60   2479   0.067      9      165
2008   7.60          6.60    158    8.60   2692   0.062      9      167
2009   7.60          6.60    168    8.60   2924   0.058      9      168
2010   7.60          6.60    179    8.60   3175   0.054      9      170
2011   7.60          6.60    191    8.60   3448   0.050      9      171
2012   7.60          6.60    204    8.60   3745   0.046      9      173
2013   7.60          6.60    217    8.60   4067   0.043      9      175
2014   7.60          6.60    232    8.60   4417   0.040      9      176
2015   7.60          6.60    247    8.60   4797   0.037      9      178
2016   7.60          6.60    263    8.60   5209   0.035      9      179
2017   7.60          6.60    281    8.60   5657   0.032      9      181
2018   7.60          6.60    299    8.60   6144   0.030      8      183
2019   7.60          6.60    319    8.60   6672   0.028      8      185
2020   7.60          6.60    340    8.60   7246   0.026      8      186
2021   7.60          6.60    363    8.60   7869   0.024      8      188

                                           TOTAL           2562     7623


          BENEFIT COST RATIO =   7623  /   2562  =  2.98

          TOTAL BENEFITS EXCEED TOTAL COSTS BY YEAR 1984
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APPENDIX D
COYOTE SITE

TABLE D1: PROJECT DATA: COYOTE

Description	Unit	Project Data	Remarks
General			
Location		5 mi S.E. of Morgan Hill	
Cost Zone Coefficient		1	
Tributary Creek		Coyote Creek	
Drainage Area	acre	77,400	
Design Capacity	Ac-ft	23,700	
Year dam completed		1936	
Head Data:			
Headwater Elevation:			
Maximum	ft	795	
Minimum	ft	704	
Tailwater Elevation at Design Discharge	ft	668	
Gross Head:			
Maximum	ft	127	
Minimum	ft	31	
Design	ft	75	
Design Net Head	ft	70	
Turbine:			
Type		Horizontal Francis	
Design Discharge	cfs	65	
Unit Capacity	kW	322	
Waterways:			
Intake Structures Required	No	None	
Penstock:			
Length:			
Main	ft	50	
Branch	ft	–	
Bifurcation Required	No	1	
Maximum Velocity	ft/sec	16	
Diameter	ft	2.5	
Bypass Structure Required	No	1	
Bypass Discharge	cfs	485	
Tailrace Length	ft	50	
Transmission Line:			
Voltage	kV	13.8	
Capacity	MW	0.40	
Length	mile	1	

TABLE D2: COST COMPILATION: COYOTE

Description	Unit	Quantity	Unit Cost $	Amount April 1979 $	Cost Indexes 1979 April	Cost Indexes 1981 July	Escalated Amount 1981 $
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	20,000	20,000	2.34	2.92	25,000
Bifurcation	No.	1	12,000	12,000	2.34	2.92	15,000
SUBTOTAL							45,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS		420,000	420,000	2.45	3.14	538,300
Equipment Adjustments:	LS						
SUBTOTAL UNIT							538,300
Bypass Structure	LS		140,000	140,000	2.34	2.92	174,700
Tailrace	LF	50	12	600	2.39	3.04	800
Switchyard:							
Civil Features	LS		9,400	9,400	2.40	2.94	11,500
Equipment	LS		66,000	66,000	2.40	2.94	80,900
SUBTOTAL							806,200
3. Special Costs:							
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							851,800
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					17,000
SUBTOTAL							868,900
5. Transmission Line:							
Line x.9 Length Factor	mile	1	26,000	23,400	2.69	3.19	27,700
6. TOTAL							896,600

TABLE D3: PROJECT COST SUMMARY: COYOTE

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	45,600.
2.	Power Plant	806,200.
3.	Special Structures	-
4.	Existing Facilities	-
5.	General Costs	17,000.
6.	Transmission Line	27,700.
7.	TOTAL DIRECT COST	896,500.
8.	Contingencies (20%)	179,300.
9.	Sub-Total	1,075,800.
10.	Engineering, Administration and Construction Management (20%)	215,200.
11.	TOTAL CONSTRUCTION COST:	$1,291,000.

TABLE D4

COYOTE DAM

BASE ENERGY PRICE= 71.04 MILLS/KWH, F1 DISCOUNT FACTOR= 0.80
ENERGY RATE USED= 56.83 MILLS/KWH, ANNUAL O&M 1.20 % OF CAPITAL COST
CAPITAL COST ($1000) = 1292.0, ANNUAL ENERGY PRODUCTION = 1000.0 MWH

YEAR	INT. RATE (%)	DEBT SERVICE ($1000)	INFL RATE (%)	O&M COSTS ($1000)	ENERGY ESC RATE (%)	ENERGY INCOME ($1000)	PW FACTOR	PRESENT VALUE COSTS ($1000)	PRESENT VALUE BENEFITS ($1000)
1982	12.00	172	9.70	17	11.70	63	0.893	169	56
1983	12.00	172	9.50	18	11.50	70	0.797	152	56
1984	12.00	172	9.10	20	11.10	78	0.712	137	55
1985	12.00	172	8.70	22	10.70	87	0.636	123	55
1986	12.00	172	8.30	23	10.30	96	0.567	111	54
1987	12.00	172	7.90	25	9.90	105	0.507	100	53
1988	12.00	172	7.50	27	9.50	115	0.452	90	52
1989	12.00	172	7.10	29	9.10	126	0.404	81	50
1990	12.00	172	6.70	31	8.70	137	0.361	73	49
1991	12.00	172	6.69	33	8.69	148	0.322	66	47
1992	12.00	172	6.68	36	8.68	161	0.287	60	46
1993	12.00	172	6.67	38	8.67	175	0.257	54	45
1994	12.00	172	6.66	41	8.66	191	0.229	49	43
1995	12.00	172	6.65	43	8.65	207	0.205	44	42
1996	12.00	172	6.65	46	8.65	225	0.183	40	41
1997	12.00	172	6.64	49	8.64	245	0.163	36	39
1998	12.00	172	6.63	53	8.63	266	0.146	32	38
1999	12.00	172	6.62	56	8.62	289	0.130	29	37
2000	12.00	172	6.61	60	8.61	314	0.116	27	36
2001	12.00	172	6.60	64	8.60	341	0.104	24	35
2002	7.60		6.60	68	8.60	370	0.096	6	35
2003	7.60		6.60	73	8.60	402	0.090	6	36
2004	7.60		6.60	77	8.60	436	0.083	6	36
2005	7.60		6.60	83	8.60	474	0.077	6	36
2006	7.60		6.60	88	8.60	515	0.072	6	37
2007	7.60		6.60	94	8.60	559	0.067	6	37
2008	7.60		6.60	100	8.60	607	0.062	6	37
2009	7.60		6.60	107	8.60	660	0.058	6	38
2010	7.60		6.60	114	8.60	716	0.054	6	38
2011	7.60		6.60	121	8.60	778	0.050	6	38
2012	7.60		6.60	129	8.60	845	0.046	6	39
2013	7.60		6.60	138	8.60	918	0.043	5	39
2014	7.60		6.60	147	8.60	997	0.040	5	39
2015	7.60		6.60	157	8.60	1082	0.037	5	40
2016	7.60		6.60	167	8.60	1175	0.035	5	40
2017	7.60		6.60	178	8.60	1277	0.032	5	41
2018	7.60		6.60	190	8.60	1386	0.030	5	41
2019	7.60		6.60	203	8.60	1506	0.028	5	41
2020	7.60		6.60	216	8.60	1635	0.026	5	42
2021	7.60		6.60	231	8.60	1776	0.024	5	42
						TOTAL		1629	1720

BENEFIT COST RATIO = 1720 / 1629 = 1.06

TOTAL BENEFITS EXCEED TOTAL COSTS BY YEAR 2019

APPENDIX E
GUADALUPE SITE

TABLE E1: PROJECT DATA: GUADALUPE

Description	Unit	Project Data	Remarks
General			
Location		S.E. San Jose	
Cost Zone Coefficient		1	
Tributary Creek		Guadalupe River	
Drainage Area	acre	3,840	
Design Capacity	Ac-ft	3,740	
Year dam completed		1936	
Head Data:			
Headwater Elevation:			
Maximum	ft	624	
Minimum	ft	577	
Tailwater Elevation at Design Discharge	ft	484	
Gross Head:			
Maximum	ft	140	
Minimum	ft	65	
Design	ft	125	
Design Net Head	ft	120	
Turbine:			
Type		Horizontal Francis	
Design Discharge	cfs	15	
Unit Capacity	kW	127	
Waterways:			
Intake Structures Required	No	None	
Penstock:			
Length:			
Main	ft	50	
Branch	ft	-	
Bifurcation Required	No	1	
Maximum Velocity	ft/sec	9.0	
Diameter	ft	1.5	
Bypass Structure Required	No	1	
Bypass Discharge	cfs	250	
Tailrace Length	ft	50	
Transmission Line:			
Voltage	kV	13.8	
Capacity	MW	0.20	
Length	mile	1	

TABLE E2: COST COMPILATION: GUADALUPE

Description	Unit	Quantity	Unit Cost $	Amount April 1979 $	Cost Indexes 1979 April	Cost Indexes 1981 July	Escalated Amount 1981 $
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	8,000	8,000	2.34	2.92	10,000
Bifurcation	No.	1	8,000	8,000	2.34	2.92	10,000
SUBTOTAL							25,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS		360,000	360,000	2.45	3.14	461,400
Equipment Adjustments:	LS						
SUBTOTAL UNIT							461,400
Bypass Structure	LS		98,000	98,000	2.34	2.92	122,300
Tailrace	LF	50	10	500	2.39	3.04	600
Switchyard:							
Civil Features	LS		9,000	9,000	2.40	2.94	11,000
Equipment	LS		66,000	66,000	2.40	2.94	80,900
SUBTOTAL							676,200
3. Special Costs:							
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							701,800
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					14,000
SUBTOTAL							715,800
5. Transmission Line:							
Line x.9 Length Factor	mile	1	26,000	23,400	2.69	3.19	27,700
6. TOTAL							743,500

TABLE E3: PROJECT COST SUMMARY: GUADALUPE

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	25,600.
2.	Power Plant	676,200.
3.	Special Structures	-
4.	Existing Facilities	-
5.	General Costs	14,000.
6.	Transmission Line	27,700.
7.	TOTAL DIRECT COST	743,500.
8.	Contingencies (20%)	148,700.
9.	Sub-Total	892,200.
10.	Engineering, Administration and Construction Management (20%)	178,400.
11.	TOTAL CONSTRUCTION COST:	$1,070,600.

TABLE E4

GUADALUPE DAM

BASE ENERGY PRICE= 71.04 MILLS/KWH, F1 DISCOUNT FACTOR= 0.80
ENERGY RATE USED= 56.83 MILLS/KWH, ANNUAL O&M 1.20 % OF CAPITAL COST
CAPITAL COST ($1000) = 1071.0, ANNUAL ENERGY PRODUCTION = 350.1 MWH

YEAR	INT. RATE (%)	DEBT SERVICE ($1000)	INFL RATE (%)	O&M COSTS ($1000)	ENERGY ESC RATE (%)	ENERGY INCOME ($1000)	PW FACTOR	PRESENT VALUE COSTS ($1000)	PRESENT VALUE BENEFITS ($1000)
1982	12.00	143	9.70	14	11.70	22	0.893	140	19
1983	12.00	143	9.50	15	11.50	24	0.797	126	19
1984	12.00	143	9.10	16	11.10	27	0.712	114	19
1985	12.00	143	8.70	18	10.70	30	0.636	102	19
1986	12.00	143	8.30	19	10.30	33	0.567	92	19
1987	12.00	143	7.90	21	9.90	36	0.507	83	18
1988	12.00	143	7.50	22	9.50	40	0.452	75	18
1989	12.00	143	7.10	24	9.10	44	0.404	67	17
1990	12.00	143	6.70	26	8.70	47	0.361	61	17
1991	12.00	143	6.69	28	8.69	52	0.322	55	16
1992	12.00	143	6.68	29	8.68	56	0.287	49	16
1993	12.00	143	6.67	31	8.67	61	0.257	44	15
1994	12.00	143	6.66	34	8.66	66	0.229	40	15
1995	12.00	143	6.65	36	8.65	72	0.205	36	14
1996	12.00	143	6.65	38	8.65	78	0.183	33	14
1997	12.00	143	6.64	41	8.64	85	0.163	30	13
1998	12.00	143	6.63	44	8.63	93	0.146	27	13
1999	12.00	143	6.62	46	8.62	101	0.130	24	13
2000	12.00	143	6.61	50	8.61	109	0.116	22	12
2001	12.00	143	6.60	53	8.60	119	0.104	20	12
2002	7.60		6.60	56	8.60	129	0.096	5	12
2003	7.60		6.60	60	8.60	140	0.090	5	12
2004	7.60		6.60	64	8.60	152	0.083	5	12
2005	7.60		6.60	68	8.60	166	0.077	5	12
2006	7.60		6.60	73	8.60	180	0.072	5	12
2007	7.60		6.60	78	8.60	195	0.067	5	13
2008	7.60		6.60	83	8.60	212	0.062	5	13
2009	7.60		6.60	88	8.60	231	0.058	5	13
2010	7.60		6.60	94	8.60	250	0.054	5	13
2011	7.60		6.60	101	8.60	272	0.050	5	13
2012	7.60		6.60	107	8.60	295	0.046	4	13
2013	7.60		6.60	114	8.60	321	0.043	4	13
2014	7.60		6.60	122	8.60	349	0.040	4	13
2015	7.60		6.60	130	8.60	379	0.037	4	14
2016	7.60		6.60	139	8.60	411	0.035	4	14
2017	7.60		6.60	148	8.60	447	0.032	4	14
2018	7.60		6.60	158	8.60	485	0.030	4	14
2019	7.60		6.60	168	8.60	527	0.028	4	14
2020	7.60		6.60	179	8.60	572	0.026	4	14
2021	7.60		6.60	191	8.60	621	0.024	4	14
						TOTAL		1350	602

BENEFIT COST RATIO = 602 / 1350 = 0.45

APPENDIX F
LEXINGTON SITE

TABLE F1: PROJECT DATA: LEXINGTON

Description	Unit	Project Data	Remarks
General			
Location		3 mi South of Los Gatos	
Cost Zone Coefficient		1	
Tributary Creek		Los Gatos Creek	
Drainage Area	acre	24,000	
Design Capacity	Ac-ft	20,210	
Year dam completed		1953	
Head Data:			
Headwater Elevation:			
Maximum	ft	661	
Minimum	ft	595	
Tailwater Elevation at Design Discharge	ft	466	
Gross Head:			
Maximum	ft	195	
Minimum	ft	129	
Design	ft	145	
Design Net Head	ft	140	
Turbine:			
Type		Horizontal Francis	
Design Discharge	cfs	85	
Unit Capacity	kW	840	
Waterways:			
Intake Structures Required	No	None	
Penstock:			
Length:			
Main	ft	50	
Branch	ft	-	
Bifurcation Required	No	1	
Maximum Velocity	ft/sec	18	
Diameter	ft	2.5	
Bypass Structure Required	No	1	
Bypass Discharge	cfs	500	
Tailrace Length	ft	50	
Transmission Line:			
Voltage	kV	13.8	
Capacity	MW	1	
Length	mile	1	

TABLE F2: COST COMPILATION: LEXINGTON

Description	Unit	Quantity	Unit Cost	Amount April 1979	Cost Indexes		Escalated Amount 1981
			$	$	1979 April	1981 July	$
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	20,000	20,000	2.34	2.92	25,000
Bifurcation	No.	1	12,000	12,000	2.34	2.92	15,000
SUBTOTAL							45,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS		550,000	550,000	2.45	3.14	704,900
Equipment Adjustments:	LS						
SUBTOTAL UNIT							704,900
Bypass Structure	LS		150,000	150,000	2.34	2.92	187,200
Tailrace	LF	50	10	500	2.39	3.04	600
Switchyard:							
Civil Features	LS		10,000	10,000	2.40	2.94	12,300
Equipment	LS		66,000	66,000	2.40	2.94	80,900
SUBTOTAL							985,300
3. Special Costs:							
Installation of 250-foot Section of Pressure Pipe on Outlet Works	LS			219,400	2.61	3.27	274,900
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							1,305,800
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					26,100
SUBTOTAL							1,331,900
5. Transmission Line:							
Line x.9 Length Factor	mile	1	26,000	23,400	2.69	3.19	27,700
6. TOTAL							1,359,600

TABLE F3: PROJECT COST SUMMARY: LEXINGTON

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	45,600.
2.	Power Plant	985,300.
3.	Special Structures	274,900.
4.	Existing Facilities	-
5.	General Costs	26,100.
6.	Transmission Line	27,700.
7.	TOTAL DIRECT COST	1,359,600.
8.	Contingencies (20%)	271,900.
9.	Sub-Total	1,631,500.
10.	Engineering, Administration and Construction Management (20%)	326,300.
11.	TOTAL CONSTRUCTION COST:	$1,957,800.

TABLE F4

LEXINGTON DAM

BASE ENERGY PRICE= 71.04 MILLS/KWH, FI DISCOUNT FACTOR= 0.80
ENERGY RATE USED= 56.83 MILLS/KWH, ANNUAL O&M 1.20 % OF CAPITAL COST
CAPITAL COST ($1000) = 1952.0, ANNUAL ENERGY PRODUCTION = 2460.0 MWH

YEAR	INT. RATE (%)	DEBT SERVICE ($1000)	INFL RATE (%)	O&M COSTS ($1000)	ENERGY ESC RATE (%)	ENERGY INCOME ($1000)	PW FACTOR	PRESENT VALUE COSTS ($1000)	PRESENT VALUE BENEFITS ($1000)
1982	12.00	261	9.70	25	11.70	156	0.893	256	139
1983	12.00	261	9.50	24	11.50	174	0.797	230	138
1984	12.00	261	9.10	30	11.10	193	0.712	207	137
1985	12.00	261	8.70	33	10.70	214	0.636	187	136
1986	12.00	261	8.30	36	10.30	236	0.567	168	134
1987	12.00	261	7.90	38	9.90	259	0.507	152	131
1988	12.00	261	7.50	41	9.50	284	0.452	137	128
1989	12.00	261	7.10	44	9.10	310	0.404	123	125
1990	12.00	261	6.70	47	8.70	337	0.361	111	121
1991	12.00	261	6.69	51	8.69	366	0.322	100	117
1992	12.00	261	6.68	54	8.68	398	0.287	90	114
1993	12.00	261	6.67	58	8.67	432	0.257	82	111
1994	12.00	261	6.66	62	8.66	470	0.229	74	107
1995	12.00	261	6.65	66	8.65	510	0.205	67	104
1996	12.00	261	6.65	70	8.65	555	0.183	60	101
1997	12.00	261	6.64	75	8.64	603	0.163	54	98
1998	12.00	261	6.63	80	8.63	655	0.146	49	95
1999	12.00	261	6.62	85	8.62	711	0.130	45	92
2000	12.00	261	6.61	91	8.61	772	0.116	40	89
2001	12.00	261	6.60	97	8.60	839	0.104	37	87
2002	7.60		6.60	103	8.60	911	0.096	9	87
2003	7.60		6.60	110	8.60	989	0.090	9	88
2004	7.60		6.60	117	8.60	1074	0.083	9	89
2005	7.60		6.60	125	8.60	1167	0.077	9	90
2006	7.60		6.60	133	8.60	1267	0.072	9	91
2007	7.60		6.60	142	8.60	1376	0.067	9	91
2008	7.60		6.60	152	8.60	1495	0.062	9	92
2009	7.60		6.60	162	8.60	1623	0.058	9	93
2010	7.60		6.60	172	8.60	1763	0.054	9	94
2011	7.60		6.60	184	8.60	1915	0.050	9	95
2012	7.60		6.60	196	8.60	2079	0.046	9	96
2013	7.60		6.60	209	8.60	2258	0.043	9	97
2014	7.60		6.60	223	8.60	2452	0.040	8	98
2015	7.60		6.60	237	8.60	2663	0.037	8	99
2016	7.60		6.60	253	8.60	2892	0.035	8	99
2017	7.60		6.60	270	8.60	3141	0.032	8	100
2018	7.60		6.60	288	8.60	3411	0.030	8	101
2019	7.60		6.60	307	8.60	3705	0.028	8	102
2020	7.60		6.60	327	8.60	4023	0.026	8	103
2021	7.60		6.60	349	8.60	4370	0.024	8	104
						TOTAL		2461	4233

BENEFIT COST RATIO = 4233 / 2461 = 1.72

TOTAL BENEFITS EXCEED TOTAL COSTS BY YEAR 2001

APPENDIX G
STEVENS CREEK SITE

TABLE G1: PROJECT DATA: STEVENS CREEK

Description	Unit	Project Data	Remarks
General			
Location		2 mi S.W. of Cupertino	
Cost Zone Coefficient		1	
Tributary Creek		Stevens Creek	
Drainage Area	acre	11,070	
Design Capacity	Ac-ft	3,600	
Year dam completed		1935	
Head Data:			
Headwater Elevation:			
Maximum	ft	543	
Minimum	ft	497	
Tailwater Elevation at Design Discharge	ft	426	
Gross Head:			
Maximum	ft	117	
Minimum	ft	71	
Design	ft	95	
Design Net Head	ft	90	
Turbine:			
Type		Horizontal Francis	
Design Discharge	cfs	20	
Unit Capacity	kW	163	
Waterways:			
Intake Structures Required	No	None	
Penstock:			
Length:			
Main	ft	50	
Branch	ft	-	
Bifurcation Required	No	1	
Maximum Velocity	ft/sec	12	
Diameter	ft	1.5	
Bypass Structure Required	No	1	
Bypass Discharge	cfs	535	
Tailrace Length	ft	50	
Transmission Line:			
Voltage	kV	13.8	
Capacity	MW	0.20	
Length	mile	1	

TABLE G2: COST COMPILATION: STEVENS CREEK

Description	Unit	Quantity	Unit Cost	Amount April 1979	Cost Indexes 1979	1981	Escalated Amount 1981
			$	$	April	July	$
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	12,000	12,000	2.34	2.92	15,000
Bifurcation	No.	1	12,000	12,000	2.34	2.92	15,000
SUBTOTAL							35,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS		375,000	375,000	2.45	3.14	480,600
Equipment Adjustments:	LS						
SUBTOTAL UNIT							480,600
Bypass Structure	LS		150,000	150,000	2.34	2.92	187,200
Tailrace	LF	50	10	500	2.39	3.04	600
Switchyard:							
Civil Features	LS		9,000	9,000	2.40	2.94	11,000
Equipment	LS		66,000	66,000	2.40	2.94	80,900
SUBTOTAL							760,300
3. Special Costs:							
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							795,900
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					15,900
SUBTOTAL							811,800
5. Transmission Line:							
Line x.9 Length Factor	mile	1	26,000	23,400	2.69	3.19	27,700
6. TOTAL							839,500

TABLE G3: PROJECT COST SUMMARY: STEVENS CREEK

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	35,600.
2.	Power Plant	760,300.
3.	Special Structures	-
4.	Existing Facilities	-
5.	General Costs	15,900.
6.	Transmission Line	27,700.
7.	TOTAL DIRECT COST	839,500.
8.	Contingencies (20%)	167,900.
9.	Sub-Total	1,007,400.
10.	Engineering, Administration and Construction Management (20%)	201,500.
11.	TOTAL CONSTRUCTION COST:	$1,208,900.

TABLE G4

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                              STEVENS CREEK DAM
BASE ENERGY PRICE= 71,04 MILLS/KWH, F1 DISCOUNT FACTOR=  0,80
ENERGY RATE USED= 56,83 MILLS/KWH,  ANNUAL O&M  1,20 % OF CAPITAL COST
CAPITAL COST ($1000) =  1210,0, ANNUAL ENERGY PRODUCTION =  422,0 MWH

YEAR  INT,   DEBT    INFL    O&M    ENERGY  ENERGY    PW    PRESENT  PRESENT
      RATE SERVICE   RATE   COSTS    ESC    INCOME  FACTOR   VALUE    VALUE
                                     RATE                    COSTS   BENEFITS
      (%)  ($1000)   (%)   ($1000)   (%)   ($1000)          ($1000)  ($1000)
1982  12,00   161    9,70     15    11,70     26    0,893     158        23
1983  12,00   161    9,50     17    11,50     29    0,797     143        23
1984  12,00   161    9,10     19    11,10     33    0,712     128        23
1985  12,00   161    8,70     20    10,70     36    0,636     116        23
1986  12,00   161    8,30     22    10,30     40    0,567     104        22
1987  12,00   161    7,90     24     9,90     44    0,507      94        22
1988  12,00   161    7,50     25     9,50     48    0,452      85        22
1989  12,00   161    7,10     27     9,10     53    0,404      76        21
1990  12,00   161    6,70     29     8,70     57    0,361      69        20
1991  12,00   161    6,69     31     8,69     62    0,322      62        20
1992  12,00   161    6,68     33     8,68     68    0,287      56        19
1993  12,00   161    6,67     36     8,67     74    0,257      50        19
1994  12,00   161    6,66     38     8,66     80    0,229      45        18
1995  12,00   161    6,65     41     8,65     87    0,205      41        17
1996  12,00   161    6,65     43     8,65     95    0,183      37        17
1997  12,00   161    6,64     46     8,64    103    0,163      34        16
1998  12,00   161    6,63     49     8,63    112    0,146      30        16
1999  12,00   161    6,62     53     8,62    122    0,130      27        15
2000  12,00   161    6,61     56     8,61    132    0,116      25        15
2001  12,00   161    6,60     60     8,60    143    0,104      23        14
2002   7,60          6,60     64     8,60    156    0,096       6        15
2003   7,60          6,60     68     8,60    169    0,090       6        15
2004   7,60          6,60     72     8,60    184    0,083       6        15
2005   7,60          6,60     77     8,60    200    0,077       6        15
2006   7,60          6,60     82     8,60    217    0,072       5        15
2007   7,60          6,60     88     8,60    236    0,067       5        15
2008   7,60          6,60     94     8,60    256    0,062       5        15
2009   7,60          6,60    100     8,60    278    0,058       5        16
2010   7,60          6,60    107     8,60    302    0,054       5        16
2011   7,60          6,60    114     8,60    328    0,050       5        16
2012   7,60          6,60    121     8,60    356    0,046       5        16
2013   7,60          6,60    129     8,60    387    0,043       5        16
2014   7,60          6,60    138     8,60    420    0,040       5        16
2015   7,60          6,60    147     8,60    456    0,037       5        16
2016   7,60          6,60    157     8,60    496    0,035       5        17
2017   7,60          6,60    167     8,60    538    0,032       5        17
2018   7,60          6,60    178     8,60    585    0,030       5        17
2019   7,60          6,60    190     8,60    635    0,028       5        17
2020   7,60          6,60    202     8,60    690    0,026       5        17
2021   7,60          6,60    216     8,60    749    0,024       5        17

                                          TOTAL            1525       726


         BENEFIT COST RATIO =    726  /   1525  =  0,48
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APPENDIX H
ANALYSES FOR DISTRICT-OWNED TURBINE AT LEXINGTON OR COYOTE SITES

TABLE H1: COST COMPILATION: COYOTE WITH DISTRICT TURBINE

Description	Unit	Quantity	Unit Cost $	Amount April 1979 $	Cost Indexes 1979 April	Cost Indexes 1981 July	Escalated Amount 1981 $
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	20,000	20,000	2.34	2.92	25,000
Bifurcation	No.	1	12,000	12,000	2.34	2.92	15,000
SUBTOTAL							45,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS						
Equipment Adjustments:	LS						280,300
SUBTOTAL UNIT							
Bypass Structure	LS		140,000	140,000	2.34	2.92	174,700
Tailrace	LF	50	12	600	2.39	3.04	800
Switchyard:							
Civil Features	LS		9,400	9,400	2.40	2.94	11,500
Equipment	LS		66,000	66,000	2.40	2.94	80,850
SUBTOTAL							548,200
3. Special Costs:							
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							593,800
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					11,900
SUBTOTAL							605,600
5. Transmission Line:							
Line x.9 Length Factor	mile	1	26,000	23,400	2.69	3.19	27,700
6. TOTAL							633,400

TABLE H2: PROJECT COST SUMMARY: COYOTE, DISTRICT TURBINE

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	45,600
2.	Power Plant	548,200
3.	Special Structures	-
4.	Existing Facilities	-
5.	General Costs	11,900
6.	Transmission Line	27,700
7.	TOTAL DIRECT COST	633,400
8.	Contingencies (20%)	126,700
9.	Sub-Total	760,100
10.	Engineering, Administration and Construction Management (20%)	152,000
11.	TOTAL CONSTRUCTION COST:	$912,100

TABLE H3

COYOTE DAM

BASE ENERGY PRICE= 71.04 MILLS/KWH, F1 DISCOUNT FACTOR= 0.80
ENERGY RATE USED= 56.83 MILLS/KWH, ANNUAL O&M 1.20 % OF CAPITAL COST
CAPITAL COST ($1000) = 912.1, ANNUAL ENERGY PRODUCTION = 753.0 MWH

YEAR	INT. RATE (%)	DEBT SERVICE ($1000)	INFL RATE (%)	O&M COSTS ($1000)	ENERGY ESC RATE (%)	ENERGY INCOME ($1000)	PW FACTOR	PRESENT VALUE COSTS ($1000)	PRESENT VALUE BENEFITS ($1000)
1982	12.00	122	9.70	12	11.70	47	0.893	119	42
1983	12.00	122	9.50	13	11.50	53	0.797	107	42
1984	12.00	122	9.10	14	11.10	59	0.712	97	42
1985	12.00	122	8.70	15	10.70	65	0.636	87	41
1986	12.00	122	8.30	16	10.30	72	0.567	78	41
1987	12.00	122	7.90	18	9.90	79	0.507	71	40
1988	12.00	122	7.50	19	9.50	87	0.452	64	39
1989	12.00	122	7.10	20	9.10	94	0.404	57	38
1990	12.00	122	6.70	22	8.70	103	0.361	52	37
1991	12.00	122	6.69	23	8.69	112	0.322	47	36
1992	12.00	122	6.68	25	8.68	121	0.287	42	35
1993	12.00	122	6.67	27	8.67	132	0.257	38	33
1994	12.00	122	6.66	28	8.66	143	0.229	34	32
1995	12.00	122	6.65	30	8.65	156	0.205	31	32
1996	12.00	122	6.65	32	8.65	169	0.183	28	31
1997	12.00	122	6.64	35	8.64	184	0.163	25	30
1998	12.00	122	6.63	37	8.63	200	0.146	23	29
1999	12.00	122	6.62	39	8.62	217	0.130	21	28
2000	12.00	122	6.61	42	8.61	236	0.116	19	27
2001	12.00	122	6.60	45	8.60	256	0.104	17	26
2002	7.60		6.60	48	8.60	278	0.096	4	26
2003	7.60		6.60	51	8.60	302	0.090	4	27
2004	7.60		6.60	55	8.60	329	0.083	4	27
2005	7.60		6.60	58	8.60	357	0.077	4	27
2006	7.60		6.60	62	8.60	388	0.072	4	27
2007	7.60		6.60	66	8.60	421	0.067	4	28
2008	7.60		6.60	71	8.60	457	0.062	4	28
2009	7.60		6.60	75	8.60	497	0.058	4	28
2010	7.60		6.60	80	8.60	539	0.054	4	28
2011	7.60		6.60	86	8.60	586	0.050	4	29
2012	7.60		6.60	91	8.60	636	0.046	4	29
2013	7.60		6.60	97	8.60	691	0.043	4	29
2014	7.60		6.60	104	8.60	750	0.040	4	30
2015	7.60		6.60	111	8.60	815	0.037	4	30
2016	7.60		6.60	118	8.60	885	0.035	4	30
2017	7.60		6.60	126	8.60	961	0.032	4	30
2018	7.60		6.60	134	8.60	1044	0.030	4	31
2019	7.60		6.60	143	8.60	1134	0.028	3	31
2020	7.60		6.60	152	8.60	1231	0.026	3	31
2021	7.60		6.60	163	8.60	1337	0.024	3	32
						TOTAL		1150	1295

BENEFIT COST RATIO = 1295 / 1150 = 1.13

TOTAL BENEFITS EXCEED TOTAL COSTS BY YEAR 2016

TABLE H4: COST COMPILATION: LEXINGTON WITH DISTRICT TURBINE

Description	Unit	Quantity	Unit Cost	Amount April 1979	Cost Indexes 1979 April	Cost Indexes 1981 July	Escalated Amount 1981
			$	$			$
1. Penstock:							
Penstock	LF	50	90	4,500	2.61	3.27	5,600
Valving	No.	1	20,000	20,000	2.34	2.92	25,000
Bifurcation	No.	1	12,000	12,000	2.34	2.92	15,000
SUBTOTAL							45,600
2. Power Plant (Type A ,B, C & D Projects):							
Total Cost, Single Unit	LS						280,300
Equipment Adjustments:	LS						
SUBTOTAL UNIT							280,300
Bypass Structure	LS		150,000	150,000	2.34	2.92	187,200
Tailrace	LF	50	10	500	2.39	3.04	600
Switchyard:							
Civil Features	LS		10,500	10,500	2.40	2.94	12,900
Equipment	LS		66,000	66,000	2.40	2.94	80,900
SUBTOTAL							561,300
3. Special Costs:							
Installation of 250-foot Section of Pressure Pipe at Outlet Works	LS			219,400	2.61	3.27	274,900
SUBTOTAL							
SUBTOTAL - ITEMS 1 THROUGH 3							881,800
4. General Costs:							
Care of Water (0;2;6%)	LS	2%					17,600
SUBTOTAL							899,400
5. Transmission Line:							
Line x.9 Length Factor	mile	1	26,000	23,400	2.69	3.19	27,700
6. TOTAL							927,100

TABLE H5: PROJECT COST SUMMARY: LEXINGTON, DISTRICT TURBINE

Base Date: July/1981

	ITEM	COSTS ($)
1.	Penstock	45,600
2.	Power Plant	561,300
3.	Special Structures	274,900
4.	Existing Facilities	-
5.	General Costs	17,600
6.	Transmission Line	27,700
7.	TOTAL DIRECT COST	927,100
8.	Contingencies (20%)	185,400
9.	Sub-Total	1,112,500
10.	Engineering, Administration and Construction Management (20%)	222,500
11.	TOTAL CONSTRUCTION COST:	$1,335,000

APPENDIX I

INFLATION FORECAST

TABLE H6

LEXINGTON DAM

BASE ENERGY PRICE= 71.04 MILLS/KWH, F1 DISCOUNT FACTOR= 0.80
ENERGY RATE USED= 56.83 MILLS/KWH, ANNUAL O&M 1.20 % OF CAPITAL COST
CAPITAL COST ($1000) = 1335.0, ANNUAL ENERGY PRODUCTION = 2146.0 MWH

YEAR	INT. RATE (%)	DEBT SERVICE ($1000)	INFL RATE (%)	O&M COSTS ($1000)	ENERGY ESC RATE (%)	ENERGY INCOME ($1000)	PW FACTOR	PRESENT VALUE COSTS ($1000)	PRESENT VALUE BENEFITS ($1000)
1982	12.00	178	9.70	17	11.70	136	0.893	175	121
1983	12.00	178	9.50	19	11.50	151	0.797	157	121
1984	12.00	178	9.10	20	11.10	168	0.712	142	120
1985	12.00	178	8.70	22	10.70	186	0.636	128	118
1986	12.00	178	8.30	24	10.30	206	0.567	115	116
1987	12.00	178	7.90	26	9.90	226	0.507	104	114
1988	12.00	178	7.50	28	9.50	247	0.452	93	112
1989	12.00	178	7.10	30	9.10	270	0.404	84	109
1990	12.00	178	6.70	32	8.70	294	0.361	76	106
1991	12.00	178	6.69	34	8.69	319	0.322	68	102
1992	12.00	178	6.68	37	8.68	347	0.287	62	99
1993	12.00	178	6.67	39	8.67	377	0.257	56	96
1994	12.00	178	6.66	42	8.66	410	0.229	50	94
1995	12.00	178	6.65	45	8.65	445	0.205	45	91
1996	12.00	178	6.65	48	8.65	484	0.183	41	88
1997	12.00	178	6.64	51	8.64	526	0.163	37	85
1998	12.00	178	6.63	54	8.63	571	0.146	34	83
1999	12.00	178	6.62	58	8.62	620	0.130	30	80
2000	12.00	178	6.61	62	8.61	674	0.116	27	78
2001	12.00	178	6.60	66	8.60	732	0.104	25	75
2002	7.60		6.60	70	8.60	795	0.096	6	76
2003	7.60		6.60	75	8.60	863	0.090	6	77
2004	7.60		6.60	80	8.60	937	0.083	6	78
2005	7.60		6.60	85	8.60	1018	0.077	6	78
2006	7.60		6.60	91	8.60	1105	0.072	6	79
2007	7.60		6.60	97	8.60	1201	0.067	6	80
2008	7.60		6.60	103	8.60	1304	0.062	6	80
2009	7.60		6.60	110	8.60	1416	0.058	6	81
2010	7.60		6.60	118	8.60	1538	0.054	6	82
2011	7.60		6.60	125	8.60	1670	0.050	6	83
2012	7.60		6.60	134	8.60	1814	0.046	6	84
2013	7.60		6.60	143	8.60	1970	0.043	6	84
2014	7.60		6.60	152	8.60	2139	0.040	6	85
2015	7.60		6.60	162	8.60	2323	0.037	6	86
2016	7.60		6.60	173	8.60	2523	0.035	5	87
2017	7.60		6.60	184	8.60	2740	0.032	5	88
2018	7.60		6.60	197	8.60	2976	0.030	5	88
2019	7.60		6.60	210	8.60	3232	0.028	5	89
2020	7.60		6.60	223	8.60	3510	0.026	5	90
2021	7.60		6.60	238	8.60	3812	0.024	5	91
						TOTAL		1683	3693

BENEFIT COST RATIO = 3693 / 1683 = 2.19

TOTAL BENEFITS EXCEED TOTAL COSTS BY YEAR 1992

INFLATION FORECAST

Figure I1 shows the inflation forecast for the next 20 years as presented by the California Energy Commission in their staff report, "California Energy Prices, 1980-2000," July 1981. The rates shown in the figure were used to escalate O&M costs over the life of the project. Energy benefits were escalated at a rate two percent above the general rates shown in the figure. As shown, the California Energy Commission expects inflation to begin to decline by 1982 and level out at slightly under seven percent by the early 1990's.

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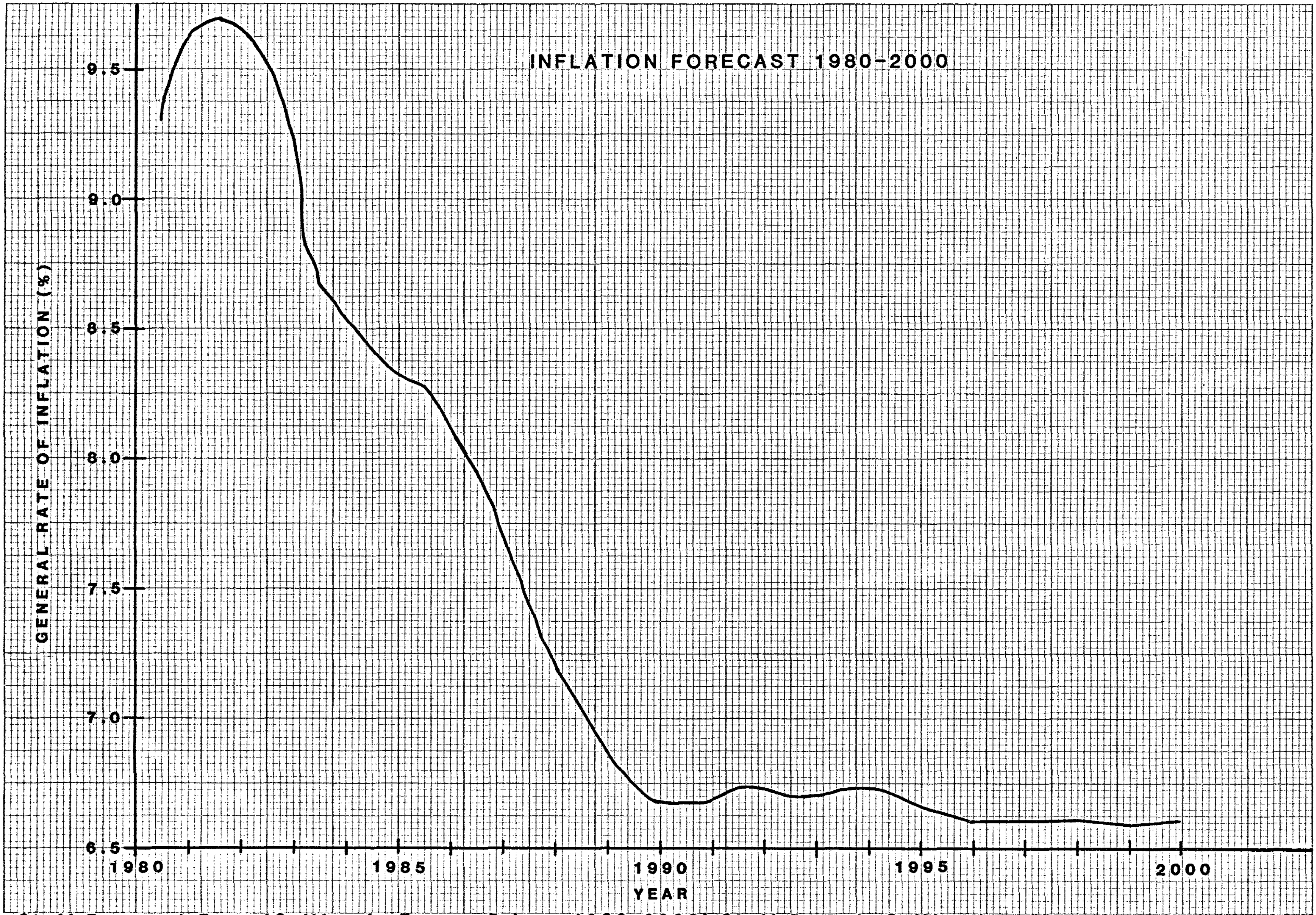

Staff Forecast From 'California Energy Prices 1980-2000' Staff Report, California Energy Commission, 1981

FIGURE I1